California Environmental Protection Agency

Air Resources Board

PUBLIC MEETING AGENDA

July 22, 2010

LOCATION:
Air Resources Board
Byron Sher Auditorium, Second Floor
1001 I Street
Sacramento, California 95814

This facility is accessible by public transit. For transit information, call (916) 321-BUSS, website: http://www.sacrt.com
(This facility is accessible to persons with disabilities.)

TO SUBMIT WRITTEN COMMENTS ON AN AGENDA ITEM IN ADVANCE OF THE MEETING GO TO: http://www.arb.ca.gov/lispub/comm/bclist.php

July 22, 2010
9:00 a.m.

DISCUSSION ITEMS:
Note: The following agenda items may be heard in a different order at the Board meeting.

Agenda Item #

10-5-3: Public Meeting to Provide a Status Report on New United States Environmental Protection Agency Requirements for Near-Roadway Monitoring of Nitrogen Dioxide (THIS ITEM WAS RESCHEDULED FROM THE MAY 27TH BOARD MEETING)

Staff will present to the Board information on new near-roadway monitoring requirements for nitrogen dioxide that were adopted earlier this year by the United States Environmental Protection Agency.

10-7-1: Public Hearing to Consider Adoption of a Proposed Regulation for a California Renewable Electricity Standard

Staff will present to the Board a proposed regulation to implement the California Renewable Electricity Standard.

10-7-2: Public Hearing to Consider Adoption of a Proposed Regulation for Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities

Staff will present to the Board a proposed regulation requiring large industrial facilities to provide information to ARB on energy usage, emissions, potential energy efficiency improvement projects, and greenhouse gas and pollutant co-benefits if the identified improvement projects were implemented.

10-7-3: Public Meeting to Update the Board on the Western Climate Initiative

Staff will update the Board on progress in the Western Climate Initiative regional greenhouse gas emissions reduction program.

CLOSED SESSION – LITIGATION

The Board will hold a closed session, as authorized by Government Code section 11126(e), to confer with, and receive advice from, its legal counsel regarding the following pending or potential litigation:

Pacific Merchant Shipping Association v. Goldstene, U.S. District Court (E.D. Cal Fresno), Case No. 2:09-CV-01151-MCE-EFB.

American Trucking Associations, et al. v. U.S. Environmental Protection Agency, et al., U.S. Court of Appeals, District of Columbia Circuit, Case No. 09-1090.

POET, LLC, et al. v. Goldstene, et al., Superior Court of California (Fresno County), Case No. 09CECG04850.

Rocky Mountain Farmers Union, et al. v. Goldstene, U.S. District Court (E.D. Cal. Fresno), Case No. 1:09-cv-02234-LJO-DLB.

National Petrochemical & Refiners Association, et al. v. Goldstene, et al., U.S. District Court (E.D. Cal. Fresno) Case No. 1:10-cv-00163-AWI-GSA.

OPPORTUNITY FOR MEMBERS OF THE BOARD TO COMMENT ON MATTERS OF INTEREST

Board members may identify matters they would like to have noticed for consideration at future meetings and comment on topics of interest; no formal action on these topics will be taken without further notice.

OPEN SESSION TO PROVIDE AN OPPORTUNITY FOR MEMBERS OF THE PUBLIC TO ADDRESS THE BOARD ON SUBJECT MATTERS WITHIN THE JURISDICTION OF THE BOARD

Although no formal Board action may be taken, the Board is allowing an opportunity to interested members of the public to address the Board on items of interest that are within the Board's jurisdiction, but do not specifically appear on the agenda. Each person will be allowed a maximum of three minutes to ensure that everyone has a chance to speak.

TO SUBMIT WRITTEN COMMENTS ON AN AGENDA ITEM IN ADVANCE OF THE MEETING GO TO:

http://www.arb.ca.gov/lispub/comm/bclist.php

IF YOU HAVE ANY QUESTIONS, PLEASE CONTACT THE CLERK OF THE BOARD:
OFFICE: (916) 322-5594
1001 I Street, Floor 23, Sacramento, California 95814
ARB Homepage: www.arb.ca.gov

SPECIAL ACCOMMODATION REQUEST

Special accommodation or language needs can be provided for any of the following:

- An interpreter to be available at the hearing;
- Documents made available in an alternate format (i.e., Braille, large print, etc.) or another language;
- A disability-related reasonable accommodation.

To request these special accommodations or language needs, please contact the Clerk of the Board at (916) 322-5594 or by facsimile at (916) 322-3928 as soon as possible, but no later than 10 business days before the scheduled Board hearing. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Comodidad especial o necesidad de otro idioma puede ser proveído para alguna de las siguientes:

- Un intérprete que esté disponible en la audiencia;
- Documentos disponibles en un formato alterno (por decir, sistema Braille, o en impresión grande) u otro idioma;
- Una acomodación razonable relacionados con una incapacidad.

Para solicitar estas comodidades especiales o necesidades de otro idioma, por favor llame a la oficina del Consejo al (916) 322-5594 o envíe un fax a (916) 322-3928 lo más pronto posible, pero no menos de 10 días de trabajo antes del día programado para la audiencia del Consejo. TTY/TDD/Personas que necesiten este servicio pueden marcar el 711 para el Servicio de Retransmisión de Mensajes de California.

SMOKING IS NOT PERMITTED AT MEETINGS OF THE CALIFORNIA AIR RESOURCES BOARD

California Environmental Protection Agency

Air Resources Board

PUBLIC MEETING AGENDA

LOCATION:
Air Resources Board
Byron Sher Auditorium, Second Floor
1001 I Street
Sacramento, California 95814

This facility is accessible by public transit. For transit information, call (916) 321-BUSS, website: http://www.sacrt.com
(This facility is accessible to persons with disabilities.)

INDEX

July 22, 2010 at 9:00 a.m.

Agenda #		Pages
10-5-3	**Public Meeting to Provide a Status Report on new United States Environmental Protection Agency Requirements for Near-Roadway Monitoring of Nitrogen Dioxide** (THIS ITEM WAS RESCHEDULED FROM THE MAY 27TH BOARD MEETING)	---
10-7-1	**Public Hearing to Consider the Adoption of a Proposed Regulation for a California Renewable Electricity Standard**	1-286
10-7-2	**Public Meeting to Consider Adoption of a Proposed Regulation for Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities**	287-396
10-7-3	**Public Meeting Update the Board on the Western Climate Initiative**	---

TITLE 17. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER ADOPTION OF A PROPOSED REGULATION FOR A CALIFORNIA RENEWABLE ELECTRICITY STANDARD

The Air Resources Board (ARB or Board) will conduct a public hearing at the time and place noted below to consider the adoption of a new regulation to reduce greenhouse gas (GHG) emissions from the electricity sector by implementing a renewable electricity standard.

DATE: July 22, 2010

TIME: 9:00 a.m.

PLACE: California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium, Second Floor
1001 I Street
Sacramento, California 95814

This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., July 22, 2010 and may continue at 8:30 a.m., July 23, 2010. This item may not be considered until July 23, 2010. Please consult the agenda for the meeting date and time, which will be available at least 10 days before July 22, 2010, to determine the day on which this item will be considered.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Sections Affected: Proposed adoption of California Code of Regulations, title 17, division 3, chapter 1, subchapter 10, article 6, California Renewable Electricity Standard, sections 97000, 97001, 97002, 97003, 97004, 97005, 97006, 97007, 97008, 97009, 97010, 97011, and 97012.

Background:
Over the last decade, California has implemented several laws and policies to expand the use of renewable energy and reduce GHG emissions from the electricity sector. These policies are outlined below.

Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002): This law established the California Renewables Portfolio Standard (RPS), which required retail sellers of electricity (electrical corporations {investor owned utilities}, community choice aggregators, and electric service providers) to procure 20 percent of their retail electric sales from renewable resources by 2017. The local publicly owned electric utilities (POUs) were encouraged, but not required, to meet the same goal. The bill delegated

Received for Filing: May 25, 2010
Publication Date: June 4, 2010

(Stamped notice can be found in Hearing Notice Binder)

specific implementation roles to the California Energy Commission (CEC) and the California Public Utility Commission (CPUC).

Energy Action Plans I (2003) and II (2005): In 2003, CEC, CPUC, and the Conservation Financing Authority (now defunct) adopted an Energy Action Plan to present a single, unified approach to meet California's electricity and natural gas needs. The Plan recommended accelerating the RPS deadline for 20 percent to 2010. The second Energy Action Plan, adopted in 2005 to reflect the policy changes and actions of the ensuing two years, recommended an accelerated goal of 33 percent renewables by 2020.

Executive Order S-3-05 (2005): In June 2005, Governor Schwarzenegger signed Executive Order S-3-05 calling for the State to reduce GHG emissions to 1990 levels by 2020 and to 80 percent below 1990 levels by 2050. The 2020 goal was established to be an aggressive, but achievable, mid-term target and the 2050 goal represents the level scientists believe is necessary to reach levels that will stabilize our climate.

Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006): This bill modified the RPS Program by requiring retail sellers of electricity (investor owned utilities, community choice aggregators, and electric service providers) to procure 20 percent of retail sales from renewable energy by 2010 as recommended in the *Energy Action Plan I*.

Assembly Bill 32 (Núñez, Ch. 488, Statutes of 2006): This law, referred to as the California Global Warming Solutions Act of 2006, required the Board to develop a plan to reduce GHG emissions in California to 1990 levels by 2020. Among other provisions, the plan must achieve the maximum technologically feasible and cost-effective reductions in GHG emissions from sources or categories of sources of GHGs by 2020.

Executive Order S-14-08 (2008): In November 2008, Governor Schwarzenegger signed Executive Order S-14-08 to accelerate the RPS target to 33 percent renewables by 2020, as recommended in the *Energy Action Plan II*.

Climate Change Scoping Plan (2008): In December 2008, the Board approved the Climate Change Scoping Plan (Scoping Plan or Plan) as required by Assembly Bill 32 (AB 32). This law sets forth a comprehensive reduction strategy that combines market-based regulatory approaches, other regulations, voluntary measures, fees, policies, and other programs to reduce California's GHG emissions to 1990 levels by 2020. The Plan identified electricity generation (which includes both in-state and out-of-state generation) as the second largest contributor to California's GHG emissions. The Plan also identified a number of measures to reduce GHG emissions from California's electricity sector, with large estimated reductions coming from implementation of the goals of Executive Order S-14-08 to achieve 33 percent renewable energy by 2020.

Executive Order S-21-09 (2009): This Executive Order, signed by Governor Schwarzenegger on September 15, 2009, directed the ARB, under its AB 32 authority, to adopt a regulation consistent with the 33 percent renewable energy target

established in Executive Order S-14-08. ARB was directed to adopt the regulation by July 31, 2010. As specified in Executive Order S-21-09, ARB:

1. May consider different approaches that would achieve the objectives of the Executive Order based on a thorough assessment of such factors as technical feasibility, system reliability, cost, GHG emissions, environmental protection or other relevant factors;

2. Shall work with the CPUC and the CEC to ensure that a regulation adopted under authority of AB 32 builds upon the RPS Program and regulates all California load serving entities, including investor-owned utilities, publicly-owned utilities, direct access providers, and community choice aggregators;

3. May delegate to CPUC and CEC any policy development or program implementation responsibilities that would reduce duplication and improve consistency with other energy programs;

4. Shall consult with California Independent System Operator (CAISO) and other load balancing authorities on, among other aspects, impacts on reliability, renewable integration requirements and interactions with wholesale power markets in carrying out the provisions of the Executive Order; and

5. Shall establish the highest priority for those resources that provide the greatest environmental benefits with the least environmental costs and impacts on public health.

The proposed regulation satisfies the directives of Executive Order S-21-09, as well as the implementation of the 33 percent renewables measure in the Scoping Plan.

DESCRIPTION OF THE PROPOSED REGULATORY ACTION

The proposed regulatory action was developed in consultation with CEC, CPUC, and CAISO. The proposed California Renewable Electricity Standard (RES) requires the State's sellers of electricity to demonstrate, by 2020, that 33 percent of the electricity sold to their retail end-use customers was generated from renewable energy resources. Increasing the portion of electricity supplied from qualifying renewable resources will reduce GHG emissions by displacing electricity produced by fossil fuel-fired electrical generating facilities.

The RES builds upon the existing California RPS Program and would establish an RES obligation that is determined by multiplying a utility's total retail electricity sales by the percentage of those sales that must come from renewable generation. Compliance with the RES obligation is demonstrated by retirement of Western Renewable Energy Generation Information System (WREGIS) certificates. WREGIS certificates document the generation of renewable energy. The credit given for such generation is called a renewable energy credit, or REC. A REC represents one megawatt-hour (MWh) of

energy generated by an eligible renewable resource. RECs will be tracked using WREGIS certificates. As stated above, these certificates represent proof that one MWh of renewable energy was generated by a renewable energy facility. Entities that are subject to the regulation would comply with the percentage of electricity sales requirement if the number of WREGIS certificates retired at the end of the compliance period is equal to, or greater than, the percentage required during that period.

To the greatest extent possible, the proposed regulation utilizes the structure, provisions, policies, and implementation mechanisms established by CEC and CPUC for the existing California RPS Program. The primary areas where the proposed regulation expands upon or diverges from the RPS Program are as follows:

- Holding the POUs to the same compliance obligations and dates as the investor-owned utilities (IOUs);
- Providing a compliance exemption threshold for the smallest utilities;
- Establishing multi-year compliance intervals; and
- Providing more flexible REC trading options to achieve GHG reductions and increase the potential availability of renewable resources. Staff's analysis supports flexible trading options. These options allow compliance at a lower cost and do not have a significant impact on utilities securing in-state vs. out-of-state resources.

The proposed regulation does not supersede the obligations that apply under the existing RPS program. A renewable generating facility that is certified by the CEC as an eligible renewable resource under the RPS will also be considered as meeting the renewable generation requirements under the proposed regulation.

Applicability

The proposed regulation would affect over 60 private and public entities including seven IOUs, eight electric service providers, and approximately 50 POUs and rural electric cooperatives. The regulation refers to these entities as the regulated parties.

Standards

The regulation would establish minimum standards that obligate a regulated party to provide a specific percentage of its total electricity sales to retail end-use customers from renewable resources by certain dates. In order to achieve the 33 percent renewables requirement by 2020, the proposed regulation would phase-in the requirement to increase the amount of electricity from eligible renewable resources over an eight-year period, starting in 2012. The tiered schedule consists of compliance intervals, each with a specified percentage of retail sales that must be generated by eligible renewable energy resources. A regulated party's compliance is demonstrated by retirement of WREGIS certificates in an amount equivalent to the RES obligation for the applicable compliance interval. Compliance with the interim standards is not

assessed until after the end of each compliance interval; however, a regulated party must measure, track, and report its status annually.

Partial Exemption

The RES obligations and compliance intervals of the proposed regulation do not apply to regulated parties that had annual sales of electricity to its retail end-use customers of 200,000 MWh or less averaged over calendar years 2007 through 2009. However, regulated parties that qualify for this partial exemption are still required to comply with certain recordkeeping and reporting provisions in order to demonstrate continued eligibility for the exemption.

Provisions Governing Use of Renewable Energy Credits

RECs reflecting generation from eligible renewable resources must be registered in and tracked by WREGIS. WREGIS issues a uniquely numbered certificate for each MWh of electricity generated by a facility registered in the system, tracks the ownership of certificates as they are traded, and retires the certificates once they are used to avoid double counting and double claims. WREGIS certificates used for compliance with the RES must be retired in WREGIS and may not be used to meet the regulatory or voluntary requirements of any other federal, state, or local program. However, a REC used for compliance with the California RPS would count toward compliance with the RES.

Banking and Trading of Renewable Energy Credits

The regulation would provide a mechanism for banking and trading of RECs. RECs that are not used by a regulated party to meet a current compliance obligation may be banked and applied toward that party's RES obligation in subsequent years or may be traded to other parties. RECs may be traded for a limited time from the date the WREGIS certificate was created and the WREGIS certificate documenting the REC must be moved to a retirement subaccount at the end of this limited time period. WREGIS certificates placed into a WREGIS retirement subaccount that are not used to meet a current RES obligation have an unlimited banking life towards meeting future RES obligations. RECs from non-RPS eligible resources held by POUs may be banked in a retirement subaccount by the original owner but cannot be sold or traded to another entity. A regulated party operating under the partial exemption may not sell, bank, or trade RECs. It should be noted that these restrictions apply to how WREGIS certificates are used to meet a RES obligation under the RES Program. They do not limit the use, banking, or trading of RECs that are not otherwise used to meet the regulation.

Recordkeeping and Reporting

The regulation would require a regulated party to submit an annual progress report, starting in 2013, and a compliance interval report during the subsequent year that immediately follows the end of the compliance period.

The annual report must include information about the regulated party and provide information about the regulated party's progress toward the RES obligation achieved over the prior calendar year.

The regulation would also require a regulated party to submit a compliance interval report following the end of a compliance interval. The compliance interval report must include information about the regulated party and provide sufficient information to determine whether the regulated party has demonstrated compliance with its RES obligation over the preceding compliance period. This information includes, but is not limited to, total retail sales to end-use customers over the compliance interval, the number of WREGIS certificates retired for the purpose of demonstrating compliance with the RES obligation, and the applicable subsection under which the regulated party calculated its RES obligation.

Additional information is required if the compliance interval report indicates that the RES obligation was not met.

Regulation Review

The regulation would require that at least three reviews be conducted to evaluate the effectiveness of the RES program. These reviews would occur in 2013, 2016, and 2018, and would be done in consultation with CEC, CPUC, and CAISO. The reviews will determine the need for program modifications and will evaluate whether any adjustments to the compliance schedules are necessary to minimize costs and maximize benefits for California's economy, improve and modernize California's energy infrastructure, maximize potential GHG and criteria pollutant emissions reductions, and maintain electric system reliability. Opportunities to harmonize the program with any federal, regional, or other state renewable portfolio standard programs or REC markets will also be considered. The reviews will be conducted using a public process and results will be presented to the Board.

Environmental Impacts:

Staff estimates that the proposed regulation would reduce GHG emissions by displacing fossil-fueled electricity generation in the Western Electricity Coordinating Council (WECC) region consistent with implementing a 33 percent renewables requirement. Overall, renewable generation produces less criteria pollutant and toxic emissions per unit of electricity output than the fossil-fuel generation it will displace. Therefore, the regulation is expected to provide an air quality benefit by reducing statewide emissions of criteria and toxic air pollutants. Certain renewable technologies, however, may

decrease these benefits and may contribute to localized impacts due to their variable nature and the need to back-up these technologies with fossil fuel-fired generation to meet demand. However, the proposed regulation is expected to result in an overall net benefit to California.

A more detailed discussion of these air quality impacts, as well as other environmental impacts, can be found in the environmental chapter of the Staff Report.

Economic Impacts:

The proposed regulatory action is considered a major regulation since the estimated costs to California business enterprises will exceed $10 million. Overall, the RES is expected to result in a slight reduction in job growth in the State. The cost of the program is expected to be passed on to electricity consumers through increased rates. However, the analysis indicates that most new renewable projects will be built in-State leading to an increase in jobs in the renewable energy sector.

A detailed discussion of these impacts can be found in the economic impacts chapter of the Staff Report.

COMPARABLE FEDERAL REGULATIONS

There are no federal regulations that mandate the reduction of GHG emissions through a renewables portfolio standard. However, there are two bills before Congress that would establish a federal-level combined efficiency and renewable electricity standard that would require each retail electricity supplier to supply an increasing percentage of its demand each year from a combination of electricity savings and renewable resources.

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

ARB staff has prepared a Staff Report: Initial Statement of Reasons (ISOR) for the proposed regulatory action, which includes a summary of the economic and environmental impacts of the proposal. The ISOR is entitled, "Initial Statement of Reasons for the Proposed Regulation for a California Renewable Electricity Standard."

Copies of the ISOR and the full text of the proposed regulatory language may be accessed on ARB's website listed below, or may be obtained from ARB's Public Information Office, Visitors and Environmental Services Center, 1001 I Street, First Floor, Sacramento, California, 95814, (916) 322-2990, at least 45 days prior to the scheduled hearing on July 22, 2010.

Upon its completion, the Final Statement of Reasons (FSOR) will be available and copies may be requested from the agency contact persons identified below, or may be accessed on ARB's website listed below.

Inquiries concerning the substance of the proposed regulation may be directed to the designated agency contact persons, Mr. David Mehl, Stationary Source Division, Energy Section Manager, at (916) 323-1491, or Mr. Gary Collord, Air Pollution Specialist, at (916) 324-5548.

Further, the agency representative and designated back-up contact persons to whom non-substantive inquiries concerning the proposed administrative action may be directed are Ms. Lori Andreoni, Manager, Board Administration & Regulatory Coordination Unit, (916) 322-4011, and Ms. Amy Whiting, Regulations Coordinator, (916) 322-6533.

The Board has compiled a record for this rulemaking action, which includes all the information upon which the proposal is based. This material is available for inspection upon request to the contact persons.

This notice, the ISOR, and all subsequent regulatory documents, including the FSOR, when completed, are also available on ARB's website for this rulemaking at http://www.arb.ca.gov/regact/2010/res2010/res2010.htm.

COSTS TO PUBLIC AGENCIES AND TO BUSINESSES AND PERSONS AFFECTED

For the purposes of this analysis, all regulated parties are treated as businesses. POUs, however, have characteristics common to both businesses and public agencies. In the context of this regulation, it is the business aspects of the POU's activities and the acquisition and sale of electricity that are affected. The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies and private persons and businesses in reasonable compliance with the proposed regulations are presented below.

Costs to State Government and Local Agencies

The ARB Executive Officer has determined that the proposed regulatory action would not create costs or savings, as defined in Government Code sections 11346.5(a)(5) and 11346.5(a)(6), to any State agency or in federal funding to the State, costs or mandate to any local agency or school district, whether or not reimbursable by the State pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code, or other nondiscretionary costs or savings to any State or local agencies.

Costs to Businesses and Private Individuals

In developing this regulatory proposal, ARB staff evaluated the potential economic impacts on representative private persons or businesses. The ARB has determined that representative private persons and businesses may be affected by the cost impacts from the proposed regulatory action. Pursuant to Government Code section 11346.5(a)(7)(C), the Executive Officer has made an initial determination that the proposed regulatory action may have a significant statewide adverse economic impact

directly affecting businesses, but is expected to have little or no effect on the ability of California businesses to compete with businesses in other states. To put the impacts of the proposed regulation into context, the higher costs associated with additional renewable electricity are estimated to translate into a six percent increase, on average, in monthly electricity bills in 2020 for households and businesses.

ARB staff has considered proposed alternatives that would lessen any adverse economic impact on businesses. The alternatives that staff considered are described in more detail in the Staff Report. ARB staff invites you to submit proposals as part of the public comment period. Submission may include the following approaches for consideration:

(i) The establishment of differing compliance or reporting requirements or timetables that take into account the resources available to businesses.

(ii) Consolidation or simplification of compliance and reporting requirements for businesses.

(iii) The use of performance standards rather than prescriptive standards

(iv) Exemption or partial exemption from the regulatory requirements for businesses.

In accordance with Government Code section 11346.3, the Executive Officer has determined that the proposed regulatory action would not affect the creation of new businesses or elimination of existing businesses within the State of California, or the expansion of businesses currently doing business within the State of California. However, the proposed regulatory action would affect the creation or elimination of jobs within the State of California. Specifically, the proposed regulatory action is expected to create jobs by increasing employment in certain business sectors, but will also eliminate jobs in other sectors resulting in a slight decrease in job growth overall.

The Executive Officer has also determined, pursuant to California Code of Regulations, title 1, section 4, that the proposed regulatory action would affect small businesses.

In accordance with Government Code sections 11346.3(c) and 11346.5(a)(11), the Executive Officer has found that the reporting requirements of the regulation which apply to businesses are necessary for the health, safety, and welfare of the people of the State of California.

Before taking final action on the proposed regulatory action, ARB must determine that no reasonable alternative considered by ARB, or that has otherwise been identified and brought to the attention of ARB, would be more effective in carrying out the purpose for which the action is proposed or would be as effective and less burdensome to affected private persons than the proposed action.

Additional information on economic impacts is addressed in the economic impacts chapter of the Staff Report.

SUBMITTAL OF COMMENTS

Interested members of the public may also present comments orally or in writing at the meeting, and comments may be submitted by postal mail or by electronic submittal before the meeting. The public comment period for this regulatory action will begin on June 7, 2010. To be considered by the Board, written comments, not physically submitted at the meeting, must be submitted on or after June 7, 2010, and received **no later than 12:00 noon, July 21, 2010**, and must be addressed to the following:

Postal mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

Please note that under the California Public Records Act (Gov. Code, § 6250 et seq.), your written and oral comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request. Additionally, this information may become available via Google, Yahoo, and other search engines.

The Board requests, but does not require, that 20 copies of any written statement be submitted and that all written statements be filed at least 10 days prior to the hearing so that ARB staff and Board Members have time to fully consider each comment. The Board encourages members of the public to bring to the attention of staff in advance of the hearing any suggestions for modification of the proposed regulatory action.

STATUTORY AUTHORITY AND REFERENCES

This regulatory action is proposed under the authority granted to ARB in Health and Safety Code sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511. The proposed regulations will implement, interpret and/or make specific Health and Safety Code sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38592, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511.

HEARING PROCEDURES

The public hearing will be conducted in accordance with the California Administrative Procedure Act, Government Code, title 2, division 3, part 1, chapter 3.5 (commencing with section 11340).

Following the public hearing, the Board may adopt the regulatory language as originally proposed, or with non-substantial or grammatical modifications. The Board may also

adopt the proposed regulatory language with other modifications if the text, as modified, is sufficiently related to the originally proposed text that the public was adequately placed on notice and that the regulatory language, as modified, could result from the proposed regulatory action. For this rulemaking, such modifications may include, but are not limited to, alternative provisions related to the use and definition of RECs, the timing of compliance with regulatory requirements and the requirements for the determination of eligible facilities. In the event that such modifications are made, the full regulatory text, with the modifications clearly indicated, will be made available to the public for written comment at least 15 days before it is adopted.

The public may request a copy of the modified regulatory text from ARB's Public Information Office, Visitors and Environmental Services Center, 1001 I Street, First Floor, Sacramento, California, 95814, (916) 322-2990.

SPECIAL ACCOMMODATION REQUEST

Special accommodation or language needs can be provided for any of the following:

- An interpreter to be available at the hearing;
- Documents made available in an alternate format (i.e. Braille, large print) or another language;
- A disability-related reasonable accommodation.

To request these special accommodations or language needs, please contact the Clerk of the Board at (916) 322-5594 or by facsimile at (916) 322-3928 as soon as possible, but no later than 10 business days before the scheduled Board hearing. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Para solicitar alguna comodidade especial o si por su idioma necesita cualquiera de los siguientes:

- Un intérprete que esté disponible en la audiencia.
- Documentos disponibles en un formato alternativo (es decir, sistema Braille, letra grande) u otro idioma.
- Una acomodación razonable relacionados con una incapacidad.

Por favor llame a la officina del Consejo a (916) 322-5594 o envie un fax a (916) 322-3928 lo mas pronto possible, pero no menos de 10 dias de trabajo antes del el dia programado para la audencia del Consejo. TTY/TDD/ Personas que nesessitan este servicion pueden marcar el 711 para el Servicio de Retransmisión de Mensajes de California.

CALIFORNIA AIR RESOURCES BOARD

James N. Goldstene
Executive Officer

Date: May 25, 2010

The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs see our website at www.arb.ca.gov.

State of California

California Environmental Protection Agency
AIR RESOURCES BOARD
Stationary Source Division

STAFF REPORT: INITIAL STATEMENT OF REASONS PROPOSED REGULATION FOR A CALIFORNIA RENEWABLE ELECTRICITY STANDARD

Public Hearing to Consider the Proposed Regulation
to Implement the Renewable Electricity Standard

Date of Release: June 3, 2010
Scheduled for Consideration: July 22-23, 2010

Location:

California Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This report has been reviewed by the staff of the Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

This Page Left Intentionally Blank

Acknowledgments

This report was prepared with the assistance and support from many individuals within the Air Resources Board; not only the principal contributors. In addition, staff would like to acknowledge the assistance and cooperation that we have received from many individuals and organizations. Finally, staff would like to acknowledge the significant contributions from the California Energy Commission, California Public Utilities Commission, and California Independent System Operator who have provided assistance throughout the rulemaking process.

Air Resources Board
Stationary Source Division
Principal Contributors

Grant Chin
Gary Collord
Joseph Fischer
Chris Gallenstein
Stephanie Kato
Luis Leyva
Camille McCallion
Andrew Mrowka
Tom Pomales
Keith Roderick
Mike Scheible
Win Setiawan
Mark Sippola
Mark Siroky
Todd Suckow
Marcelle Surovik
Lea Yamashita
Lynn Yeung

Special Thanks To:

Office of Legal Affairs
Diana Jeschke
George Poppic

Research Division
Corey Bock
Reza Mahdavi
Janet Schlosser
Guihua Wang

Planning and Technical Support Division
Larry Hunsaker
Chris Nguyen

Enforcement Division
Judy Lewis
Kitty Oliver

California Energy Commission
Kevin Barker
Pam Doughman
Angela Gould
Karen Griffin
Michael Nyberg
Heather Raitt
Jim Woodward
Kate Zocchetti

California Public Utilities Commission
Amy Baker
Paul Douglas
Sara Kamins
Dina Mackin
Scott Murtishaw
Kristin Ralf-Douglas
Steve Roscow

Acknowledgments
(Continued)

California Independent System Operator
Udi Helman
Phil Pettingill

University of California, Berkeley
Peter Berck

Energy and Environmental Economics
Arne Olsen
Doug Allen
Nick Schlag

Ascent Environmental
Sydney Coatsworth
Amanda Olekszulin
Amber Giffin

Reviewed by:

Robert D. Fletcher, Deputy Executive Officer
Richard Corey, Chief, Stationary Source Division
Michael Tollstrup, Chief, Project Assessment Branch
Barbara Fry, Chief, Measures Assessment Branch
Tony Andreoni, Chief, Research and Economic Studies Branch
David Mehl, Manager, Energy Section
Terrel Ferreira, Manager, Greenhouse Gas Measures Section
Jim Nyarady, Manager, Strategy Evaluation Section
Fereidun Feizollahi, Manager, Economic Studies Section
Kitty Howard, Manager, Regulatory Assistance Section

TABLE OF CONTENTS

		Page Number
EXECUTIVE SUMMARY		ES-1
I.	INTRODUCTION	I-1
	A. Greenhouse Gases and Climate Change	I-1
	B. Legislative and Policy Directives Relating to Renewable Energy	I-2
	C. Public Process for Development of the RES	I-5
II.	STATUTORY REQUIREMENTS	II-1
III.	OVERVIEW OF THE CALIFORNIA ELECTRICITY SECTOR	III-1
	A. Electricity Transmission and Oversight	III-1
	B. Power Generation in California	III-2
	C. California's Primary Energy Entities	III-9
	D. Air Resources Board's Role in the Electricity Sector	III-10
	E. Federal Agency Involvement in Electricity Activities	III-11
IV.	OTHER RENEWABLE ENERGY ACTIVITIES	IV-1
	A. California Renewables Portfolio Standard	IV-1
	B. Out-of-State Renewable Programs	IV-5
	C. Federal Renewable Portfolio Standard	IV-8
	D. Energy Agency Activities for 33 Percent Renewables Portfolio Standard	IV-8
	E. Electricity Transmission Activities	IV-9
	F. Scoping Plan Measures	IV-10
	G. Renewable Energy Incentive Programs	IV-13
V.	TECHNOLOGY ASSESSMENT	V-1
	A. Description of Renewable Resources	V-1
	B. Renewable Generation Development	V-8
	C. Potential Renewable Resources to Satisfy the Proposed 33 Percent RES	V-15
	D. Transmission and Grid Operation Considerations for Integrating Renewable Generation	V-30
VI.	RENEWABLE ENERGY CREDITS (RECs)	VI-1
	A. Description of RECs	VI-1
	B. CPUC's Decision on Tradable RECs (TRECs)	VI-5

VII. REGULATORY DESIGN ASSESSMENT VII-1
A. Comparison of the RPS Program to the Proposed RES VII-1
B. Primary Areas Where the Proposed RES Diverges from the RPS Program VII-2

VIII. SUMMARY AND RATIONALE FOR THE PROPOSED REGULATION VIII-1
A. Overview of the Proposed Regulation VIII-1
B. Purpose VIII-1
C. Applicability VIII-2
D. Partial Exemption VIII-2
E. Definitions VIII-3
F. Renewable Electricity Standard Obligations VIII-5
G. Renewable Electricity Standard Requirements VIII-7
H. Banking and Trading of RECs VIII-8
I. Monitoring, Verification, and Compliance VIII-9
J. Certification of Eligible Renewable Energy Resources VIII-9
K. Interagency Cooperation VIII-9
L. Enforcement VIII-10
M. Confidential Information VIII-10
N. Regulation Review VIII-10
O. Severability VIII-11
P. Rational for the Proposed Regulation VIII-11

IX. ENVIRONMENTAL IMPACTS IX-1
A. Summary of the Environmental Analysis IX-2
B. GHG Emission Benefits from Renewable Generation IX-4
C. Air Quality Impacts IX-5
D. Public Health Impacts IX-21
E. Impacted Communities IX-22
F. Other Environmental Impacts IX-29

X. ECONOMIC IMPACTS X-1
A. Summary of the Economic Impacts X-1
B. Legal Requirements X-2
C. Cost Estimation X-2
D. Cost-Effectiveness X-7
E. Impact on Residential Electricity Bills X-7
F. Impact on Small Business X-11
G. Impact on State Economy X-13
H. Green Job Impacts X-18
I. Potential Cost to Local, State, and Federal Agencies X-21

XI. ALTERNATIVES ANALYSIS XI-1
A. No Project XI-1
B. In-State Renewable Generation Only (33 Percent RES Alternative) XI-3

XII. IMPLEMENTATION AND ENFORCEMENT XII-1
A. Reporting Requirements XII-1
B. Monitoring and Verification Requirements XII-3
C. Certification of Eligible Renewable Resources XII-3
D. Recordkeeping Requirements XII-4
E. Enforcement XII-4
F. Interagency Cooperation XII-7

List of Appendices

Appendix A: Proposed Regulation Order

Appendix B: Supporting Documentation for the Technology Assessment

Appendix C: Supporting Documentation for the Regulatory Design Assessment

Appendix D: Supporting Documentation for the Environmental Analysis

This Page Intentionally Left Blank

Executive Summary

Background

In 2002, a new State law established the basic policy framework for the increased use of renewable energy in California.[a] In the policy, the focus was placed on electricity providers under the jurisdiction of the California Public Utilities Commission (CPUC). Very specific requirements were established for these providers, including a 20 percent target and the types of renewable resources that could be used to meet the target. The major eligible renewable energy resources, as defined by the California Energy Commission (CEC), include biomass, geothermal, solar, wind, and small hydroelectric facilities. This program is referred to as the Renewable Portfolio Standard (RPS). Under the new State law, the publically-owned utilities were directed to pursue voluntary actions to increase the use of renewable energy in their portfolios, but were given the flexibility to define their targets and the types of resources that would be used to meet those targets. In general, the resources were typically the same with the exception that power from some large hydroelectric facilities was included.

In 2008, about 10 percent of the total California electricity demand was met by CEC-defined renewable resources. In addition, about 10 percent of the demand was met by power from large hydroelectric facilities and another 15 percent was met by power from nuclear facilities. The remaining demand was met by natural gas and coal. Thus, about one-third of California's electricity demand was met by resources other than natural gas and coal. In 2012, most electricity providers are expected to meet the 20 percent target using CEC-defined eligible resources. Consequently, as much as 45 percent of California's electricity demand could be met by resources other than natural gas and coal.

As the implementation of the 20 percent renewable energy program continued, new State policy heightened the need to focus on renewable energy. Specifically, in 2006, Governor Schwarzenegger signed Assembly Bill 32, the California Global Warming Act of 2006. This new State law required the Air Resources Board (ARB or Board) to develop an overall plan, and adopt measures as appropriate, to ensure that the emissions of greenhouse gases (GHG) were reduced to 1990 levels by 2020. In December 2008, the Board adopted California's Climate Change Scoping Plan. In developing the plan, ARB staff worked closely with CPUC, CEC, and the California Independent System Operator (CAISO), among other stakeholders, to identify various energy-related measures that could substantially reduce GHG emissions. One of the key measures included in the Plan was the need to increase the amount of renewable

[a] Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002) established the RPS program, requiring retail seliers of electricity regulated by the CPUC to procure 20 percent of their retail electric sales from renewable resources by 2017. The POUs were encouraged, but not required, to meet the same goal. The law delegated specific implementation roles to the CEC and the CPUC. Senate Bill 107 (Simitian, Chapter 464, Statutes of 2006) modified the RPS program by requiring retail sellers of electricity regulated by the CPUC to meet the 20 percent target by 2010.

energy used to meet California electricity demand to 33 percent by 2020. Renewable energy reduces GHG emissions by displacing the amount of electricity derived from fossil fuels.

Recognizing the critical importance of this measure, Governor Schwarzenegger issued Executive Order S-21-09 on September 15, 2009. This Executive Order directed the ARB, under its AB 32 authority, to adopt a regulation by July 31, 2010. The regulation was to be consistent with a 33 percent renewable energy target. In developing the regulation, the Executive Order specifies that ARB:

1. May consider different approaches that would achieve the objectives of the Executive Order based on a thorough assessment of such factors as technical feasibility, system reliability, cost, GHG emissions, environmental protection or other relevant factors;

2. Shall work with the CPUC and the CEC to ensure that a regulation adopted under authority of AB 32 builds upon the RPS Program and regulates all California load serving entities, including investor-owned utilities, publicly-owned utilities, direct access providers, and community choice aggregators;

3. May delegate to the CPUC and the CEC any policy development or program implementation responsibilities that would reduce duplication and improve consistency with other energy programs;

4. Shall consult the CAISO and other load balancing authorities on, among other aspects, impacts on reliability, renewable integration requirements and interactions with wholesale power markets in carrying out the provisions of the Executive Order; and

5. Shall establish the highest priority for those resources that provide the greatest environmental benefits with the least environmental costs and impacts on public health.

Consistent with the Executive Order, ARB staff has worked closely with the energy agencies to prepare a proposed regulation to implement a 33 percent renewable energy standard. This proposed regulation is referred to as the California Renewable Electricity Standard (RES) and is the subject of this rulemaking.

The remainder of this Executive Summary provides a synopsis of the staff's proposal, including a discussion of the potential environmental and economic impacts, as well as a discussion of the alternatives considered. Details of the staff's proposal are presented in the Staff Report, entitled "Proposed Regulation for a California Renewable Electricity Standard."

Summary of the Major Findings

In developing the RES, ARB staff worked closely with the CPUC, CEC, and CAISO. The objective was to use, to the greatest extent practicable, the structures, policies, and implementation mechanisms established for the existing RPS. Thus, the RES program complements, builds upon, and in no way changes, the RPS Program. Furthermore, the proposed regulation was structured to provide flexibility to minimize costs, deliver significant GHG and criteria pollutant emission reductions, provide certainty with clear goals for long-term planning, and protect jobs and business competitiveness within the State. The major findings associated with the proposal are listed below.

- The 33 percent renewable target by 2020 is achievable.
- The proposed RES will reduce GHG emissions from California's electricity sector by at least 12 million metric tons of carbon dioxide equivalent ($MMTCO_2E$) in 2020, making it one of California's largest GHG emission reduction strategies.
- The proposed RES meets the Scoping Plan commitments for GHG emission reductions in 2020 and is needed to achieve the State's mandate for reducing GHG emissions to 1990 levels by 2020.
- In addition to reducing emissions of GHGs, the proposal would result in hundreds of tons of statewide reductions in both criteria and toxic air pollutants by displacing the use of dirtier fossil-fueled generation, thus providing health-related co-benefits.
- The proposed RES helps California diversify the current energy supply, promotes energy security, builds on California's leadership as a center for green technologies by fostering a growing market for renewable technologies, including wind and solar, and supports the creation of new green jobs as part of that growing market.
- There is a cost associated with increasing the amount of renewable energy from 20 percent to 33 percent because renewable energy resources are more costly than conventional resources and there may be a need to build some additional transmission lines.
- Staff estimates that the costs to go from the existing 20 percent RPS to the proposed 33 percent RES will be about $2.5 billion in 2020. This estimate is conservative as it assumes that the costs of renewables will not decrease over time, contrary to the view held by most experts.
- Costs of the program translate into average monthly utility bill increases in 2020 of between three and ten percent for residential users depending on overall energy usage, and about six percent for small businesses.
- The cost-effectiveness of the proposal is estimated to be about $\$200/MMTCO_2E$ in 2020.
- Due to the proposed RES, estimated net job growth in 2020 is slightly less (0.08 percent) than growth without the proposed RES.
- Wind and solar are expected to provide the vast majority of new renewable energy resources.

- Over 80 percent of the new renewable energy resources are expected to be built in California. This will result in the creation of between 8,000 and 10,000 new green jobs.
- Generally, emissions at the local level are also expected to be lower with the RES, although there may be some exceptions where gas-fired generation is needed to support intermittent operation of some renewable resources.
- There may be adverse environmental impacts associated with the construction and operation of renewable energy resources, including the construction and operation of transmission lines necessary to support the proposed RES. These impacts must be addressed as part of the siting and permitting process.

Establishing the RES is one of several important measures needed to reduce GHG emissions from the electricity sector. Additional measures discussed in the Scoping Plan address energy efficiency, combined heat and power (CHP) generation, and distributed generation (specifically solar energy systems used on residential, commercial, government, and non-profit buildings). In addition, entities that are part of California's electricity sector are expected to be included in ARB's Cap-and-Trade Program. Collectively, these programs are expected to complement each other.

Summary of the Existing California RPS Program

As briefly discussed above, the California RPS program requires retail sellers of electricity regulated by the CPUC to increase the amount of renewable energy they procure until 20 percent of their retail sales are served with renewable resources. Retail sellers of electricity are required to meet 20 percent by December 31, 2010, and maintain this level annually thereafter. The RPS applies to large and small investor owned utilities (IOUs), multi-jurisdictional utilities, electric service providers, and community choice aggregators. State law also requires local publicly owned electric utilities (POUs) to expand their use of renewable generation, but gives them flexibility in developing specific targets and timelines.

The RPS program is collaboratively implemented by the CEC and the CPUC. The CEC is responsible for certifying renewable facilities as eligible for the RPS and operating the accounting system to track and verify RPS compliance. The CPUC is responsible for determining annual procurement targets, reviewing and approving each utility's renewable energy procurement plan, reviewing contracts for RPS-eligible energy, and ensuring compliance.

Under the RPS, the procurement of energy from a renewable facility cannot be counted toward an affected retail seller's compliance unless that facility has been certified as RPS-eligible by the CEC, and the facility's energy production has been tracked through the Western Renewable Energy Generation Information System (WREGIS). This is an independent renewable energy tracking system for the region covered by the Western Electricity Coordinating Council (WECC). WREGIS tracks renewable energy generation from resources that register in the system. WREGIS issues a certificate for a "renewable energy credit", or "REC." This REC represents one megawatt-hour (MWh)

of renewable electricity generated from a certified renewable facility. A WREGIS Certificate, and therefore the underlying REC, can be used only once. The CEC certifies a facility according to the eligibility requirements found in CEC's Renewables Portfolio Standard Eligibility Guidebook (Guidebook).[b]

Nationwide Efforts to Develop Renewable Energy

Nationwide, 29 states and the District of Columbia have renewable portfolio standards. Six other states have nonbinding, voluntary renewable energy goals. Eight states other than California that are within the WECC region have adopted their own mandatory renewable programs, with varying percent renewables requirements and compliance dates. The WECC's service territory includes all of California and all or portions of 13 other states; the provinces of Alberta and British Columbia; and the northern portion of Baja California, Mexico.

Although there is currently no federal RPS program, two Congressional bills are in development, which would establish such a program. The American Clean Energy and Security Act of 2009 (H.R. 2454, Waxman) establishes a combined efficiency and renewable electricity standard that requires each retail electricity supplier selling four million megawatt-hours (MWh) or more of electricity to consumers to supply an increasing percentage of its demand each year from a combination of electricity savings and renewable resources. The Federal Energy Regulatory Commission (FERC) would establish regulations to implement the standard. This standard would be required to incorporate the best practices of existing state and tribal renewable electricity programs and provide for the issuance, tracking, verification, and identification of RECs. This bill would allow RECs to be banked for three years.

The American Clean Energy Leadership Act of 2009 (S. 1462, Bingaman) establishes a combined efficiency and renewable electricity standard that requires each retail electricity supplier that sells four million MWh or more of electricity to consumers to supply a specified percentage of its demand each year from a combination of electricity savings and renewable resources. Efficiency measures can satisfy up to 26.67 percent of a utility's renewables requirement. The U.S. Department of Energy would be required to establish a renewable energy credit trading program and an energy efficiency credit trading program, under which utilities submit credits to comply with the standards. This bill would also allow RECs to be banked for three years.

ARB staff will continue to monitor federal activities and at such time that a federal program is implemented develop recommendations for aligning federal and state programs.

[b] The Guidebook can be found at: http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF

Major Provisions of the Proposed RES

ARB staff worked closely with staff from the CEC, CPUC, and CAISO in developing the proposed regulation. In addition, staff met with multiple utilities and other stakeholders to develop the proposed RES. As part of its evaluation of the proposed regulation, staff addressed the criteria identified in Health and Safety Code section 38562 that must be considered for proposed regulations such as the RES. The key applicable criteria are summarized below and addressed in detail in the Staff Report.

- Establish an open public process.
- Consider regulatory provisions that minimize costs and maximize benefits.
- Ensure that the regulation does not disproportionately impact low-income communities.
- Evaluate cost-effectiveness.
- Consider the potential impacts on federal and State ambient air quality standards.
- Include provisions that minimize any administrative burden resulting from the regulation.
- Consider the sources' contribution to statewide emissions of GHGs.
- Consider the best economic and scientific information in evaluating impacts of the regulation.

ARB has addressed each of these criteria as part of its evaluation. A detailed description of the criteria and staff's evaluation is included in the Staff Report. The current RPS program is an important baseline for developing the proposed RES program. The key provisions of the proposed RES regulation are discussed below.

Applicability

The proposed regulation would require essentially all electricity providers serving California to meet a 33 percent renewable standard by 2020. This includes nearly 65 private and public retail sellers of electricity including seven investor-owned utilities (IOU), eight electricity service providers (ESP), and approximately 50 publically-owned utilities (POU) and rural electric cooperatives.[c] This differs from the existing RPS program by requiring all POUs to fall under direct regulatory requirements, as opposed to the current voluntary program.

Only the recordkeeping and reporting provisions of the proposed regulation would apply to the California Department of Water Resources (DWR) and the Western Area Power Administration (WAPA).

The affected entities are collectively referred to as regulated parties.

[c] Investor-owned utilities include San Diego Gas and Electric, Southern California Edison, and Pacific Gas and Electric. Publically-owned utilities include the Sacramento Municipal Utility District and the Los Angeles Department of Water and Power.

Partial Exemptions

The requirements to meet specified RES target obligations would not apply to retail sellers of electricity that annually provided 200,000 MWh or less of total electricity sales to retail end-use customers. The baseline is determined by averaging retail sales over calendar years 2007 through 2009. However, regulated parties that qualify for this partial exemption would be required to comply with recordkeeping and reporting provisions. In addition, a regulated party formed after September 2009 is not eligible for a partial exemption.

In evaluating the impacts of the proposed RES, staff found that regulated parties at or below the 200,000 MWh threshold would typically experience twice the administrative costs relative to their costs of compliance compared to retail providers above this threshold.

Recognize POU Voluntary Commitments Made on Renewables

As discussed above, POUs do not have a statutory requirement to meet a 20 percent renewable standard. The POUs are allowed to self-certify renewable resources and set their own renewable targets. Even though voluntary, many POUs have made good progress in acquiring renewable resources. Because the RES establishes equivalent requirements for all California load serving entities, staff believes it to be an issue of equity to allow POUs that voluntarily made progress to increase the use of renewable energy to get credit under the RES. This would include credit for non qualifying self-certified resources. In order to qualify under the RES, the renewable resource had to be approved by the POU's governing board and reported to the CEC between January 1, 2003 and September 15, 2009. In addition, these renewable resources could not exceed 20 percent of a POU's retail sales for RES compliance. The POUs would be required to provide the remainder of their RES obligation with CEC certified eligible renewable resources. This credit would expire as the contracts expire.

RES Obligation

The 33 percent standard is phased-in over an eight-year period, starting on January 1, 2012, with four primary compliance periods, each with its own REC percentage requirements. Table 1 shows the interim percentage requirements and corresponding compliance dates.

Table 1
Compliance Obligations

Compliance Intervals	Percentage of Renewable Energy Retail Sales
2012 through 2014	20
2015 through 2017	24
2018 through 2019	28
2020 and annually thereafter	33

The multiple year compliance intervals were established to ensure steady progress towards meeting 33 percent by 2020 target. The multiple year intervals allow utilities to balance their portfolios to make up for annual load fluctuations and the availability of renewables and transmission. Staff believes that these multi-year intervals are particularly important in the early years as transmission and renewable facilities are being planned and built. In later years, as the infrastructure gets put in place, these multi-year intervals become less critical and by 2020 annual targets are specified.

Compliance with the interim standards is based on calculating the regulated party's RES obligation (in MWh) and comparing that value to the number of WREGIS certificates retired (each certificate represents a REC). Although compliance with the interim standards is not assessed until the end of each compliance interval, regulated parties must measure, track, and report their status annually. The RES obligation for a given compliance interval is determined using the following formula:

RES Obligation = Sum of retail sales for the compliance interval (in MWh) times the REC percentage for the compliance interval

Additional procedures for calculating the RES obligation are included for a regulated party that loses its partial exemption and for a regulated party with significant large hydroelectric resources.

Allowable Renewable Energy Credits

As discussed above, RECs are used to verify and track the creation and use of renewable electricity. RECs are widely used in the U.S for both voluntary green claims and compliance with state RPS programs. RECs used for compliance with the regulation must be registered in and tracked by WREGIS. WREGIS issues a uniquely-numbered certificate for each MWh of electricity generated by a facility

registered in the system, tracks the ownership of certificates as they are traded, and retires the certificates once they are used to avoid double counting. RECs used for compliance with the RES must be retired in WREGIS and may not be used for compliance with any other federal, state, or local program. However, a REC used for compliance with a complimentary renewables compliance obligation, such as the California RPS, would count toward compliance with the RES.

RECs that may be used to comply with the proposed regulation are summarized below.

- RECs from a renewable generating facility that is certified by the CEC as eligible for the RPS program.

- RECs from a renewable generating facility that meets the criteria for a RPS-eligible resource, excluding electricity delivery requirements for out-of-state generation.

- RECs from a renewable generating facility that meets the criteria for a RES Qualifying POU Resource. The proposed regulation restricts the amount of RECs from a RES Qualifying POU Resource that may be used by the initial POU owner or procurer for RES compliance. This amount is capped at 20 percent of the POU's retail sales to end-use customers during calendar year 2010.

Contracts for RECs can include the delivery of the associated electricity or can specify that the RECs are being purchased separately from the electricity. When RECs are purchased without the associated electricity, they are referred to as *unbundled RECs*. Similarly, a transaction where both the REC and the associated renewable energy are sold together is known as a *bundled REC*. Historically, RECs procured under the existing California RPS program have been bundled RECs.

In developing the RES, staff evaluated the impacts of allowing the unlimited use of unbundled, undelivered RECs for compliance with the RES. The additional flexibility of providing no restrictions on RECs is expected to lower costs by increasing compliance options. As each REC represents a MWh of renewable generation, GHG reductions are guaranteed to have occurred.

Staff's analysis compared two scenarios: one assuming there would be no limitations on the use of RECs to meet the 33 percent RES requirement; the other leaving the current requirements for bundling and delivery in place to meet the same target. Based on this comparison, it was found that there was little difference in the resource mix, in-state versus out-of state resources, or emission reductions. The biggest difference was in the cost with an approximate seven percent reduction in costs for the scenario with no restrictions on the use of RECs. Staff believes the greatest benefits occur in the early years of the RES program. Removing any restrictions on the use of RECs is expected to provide more flexible compliance options as planning, permitting, and construction of renewable resources and transmission occurs.

As a result staff has not included any restrictions on the use of RECs in the proposed RES regulation. The proposal allows needed flexibility, especially for short-term compliance needs, reduces the overall costs associated with a renewables program, ensures emission reductions of GHGs and criteria pollutant emissions will occur, and is not expected to significantly increase the demand for out-of-state renewable resources.

Certification of Eligible Renewable Energy Resources

Certifying RPS-eligible facilities falls under the CEC's current statutory authority. The CEC certifies RPS-eligible facilities regardless of whether the energy and RECs are procured by parties subject to the RPS, by POUs, or by another entity. The CEC would continue this role after the adoption of the proposed regulation. Applicants seeking certification of a renewable energy facility for eligibility under the existing RPS program would file the application with the CEC in accordance with their review process.

The CEC does not have statutory authority, however, to certify or register facilities for POUs (or any entity) that do not meet the statutory requirements for RPS-eligibility. Under the proposed regulation, this would include facilities not meeting the delivery requirement of the RPS program and facilities eligible as a RES Qualifying POU Resource, in addition to the POU resources. These applicants would file the application with the ARB Executive Officer. However, ARB staff is exploring mechanisms by which the ARB would receive the application for non-RPS eligible facilities and enter into an interagency agreement with CEC or a third party contractor to review and make recommendations regarding certification and verification of the resource for the RES program.

Banking and Trading of Renewable Energy Credits

The proposed regulation provides a mechanism for both regulated and non-regulated parties (such as brokers) to bank and trade RECs. RECs that are not used by a regulated party to meet a current compliance obligation may be banked and applied toward that party's obligations in subsequent years or may be traded to other parties, including third party brokers not subject to the RES. Some additional trading restrictions are imposed. First, a REC is subject to a three-year retention and trading window – in other words, a REC may be retained or traded for up to three calendar years from the date WREGIS issued the certificate, including the certificate issuance year, or until a REC is retired into a WREGIS retirement subaccount, whichever of these events occurs first. Second, a REC must be moved to a WREGIS retirement subaccount within three years of its generation or acquisition to be used for RES compliance; however, RECs placed in a retirement subaccount that are not used to meet a current RES obligation have an unlimited banking life. Third, a REC generated or procured from a RES Qualifying POU Resource may be banked by the original owner of the REC, but cannot be traded or sold. Lastly, a REC generated or procured by an entity that qualifies for the partial exemption as a small regulated party may not be banked, traded, or sold.

The banking and trading restrictions imposed by the proposed regulation apply to RECs used to meet a RES obligation. They do not limit the use, banking, or trading of RECs that are not used to meet the requirements of the regulation.

Reporting and Recordkeeping

The regulation would require the responsible official of a regulated party to submit an annual progress report, starting July 1, 2013, and a compliance interval report, by July 1st of the year following the end of the compliance period (in lieu of an annual report).

The annual report must contain information on the regulated party (e.g., contact information, WREGIS account identification number) and RES annual progress information (e.g., WREGIS certificates retired for reporting year by facility identification number, retail sales to end-use customers for reporting year).

The compliance interval report must contain information necessary to assess compliance with the renewable targets specified in Table 1 (e.g., contact information, WREGIS account identification number, WREGIS certificates retired over the compliance interval, total retail sales to end-use customers for the compliance interval, and RES obligation for the compliance interval). Additional information is required if the compliance interval report indicates that the RES obligation was not met.

To the extent they satisfy the information required under the RES, a regulated party may submit documents to ARB used to meet requirements of another regulatory agency such as the CPUC and CEC. Regulated parties would also be required to maintain and have this information available for ARB staff to inspect and verify.

Enforcement Provisions

Consistent with authority granted under AB 32, the ARB would monitor compliance and enforce the RES regulation. ARB expects to enforce the requirements of the RES, in cooperation with CEC and CPUC, to ensure that all regulated parties are in compliance. Penalties and other remedies for violations of regulations adopted pursuant to AB 32, which include the proposed RES, are set forth in Health and Safety Code (H&SC) section 38580 et seq. These include injunctive relief under H&SC section 41513 and criminal and civil penalties under H&SC section 42400 et seq., and H&SC section 43025 et seq.

Regulation Review

The regulation would require that at least three reviews be conducted to evaluate the effectiveness of the RES program and recommend adjustments as appropriate. These reviews would occur in 2013, 2016, and 2018, and would be done in coordination with the energy agencies, the regulated parties, and other interested stakeholders.

The reviews will determine the need for program modifications. The reviews would address whether any adjustments to the compliance schedules are necessary to minimize costs and maximize benefits for California's economy, improve and modernize California's energy infrastructure, maximize potential GHG and criteria pollutant emissions, and maintain electric system reliability. The GHG benefits from the implementation of the proposed RES will be determined by converting the percent renewables information in the regulated parties' annual progress reports to GHG emission reductions.

Opportunities to harmonize the program with any federal, regional, or other state renewable portfolio standard programs or REC markets will also be considered. The reviews will be conducted using a public process with results presented to the Board.

Environmental Impacts

Increasing the portion of electricity supplied from renewable resources will reduce GHG emissions by displacing electricity produced by fossil fuel-fired electrical generating facilities. The RES will reduce GHG emissions from California's electricity sector by about 12 to 13 $MMTCO_2E$ by 2020.

Overall, the expected mix of renewable generation from the implementation of the proposed RES will substantially reduce criteria pollutant and toxic emissions per unit of electricity output compared to the fossil-fuel generation it will replace. Therefore, the proposed RES will provide an overall air quality benefit by reducing statewide emissions of criteria and toxic air pollutants.

Some localized air impacts may occur in areas where new renewable generation facilities are sited. The criteria pollutant and toxic emissions associated with new renewable generation facilities will be subject to local air district permitting and California Environmental Quality Act (CEQA) requirements. If the new facility is located on federal land, it will also be subject to federal requirements under the National Environmental Policy Act (NEPA).

Not all renewable technologies provide the operating characteristics that the State's electricity system needs to maintain local area reliability. Thus, integrating these technologies can make it more difficult to operate the electricity system reliably. Although some technologies like geothermal and biomass can provide steady baseload power, technologies such as wind and solar are intermittent and not always available when needed during demand peak hours. Intermittent technologies can drop-off or pick-up suddenly, requiring quick action by system operators to compensate for sudden changes. CAISO and other balancing authorities are working together to address these challenges to ensure that the grid is reliable as new renewable resources are brought on line.

However, in some areas, there may be a need for additional gas-fired generation to assist with balancing these intermittent resources. Another option to successfully

integrate intermittent resources is the use of energy storage technologies. If natural gas-fired power plants are used, the overall statewide impacts are reduced somewhat and some localized air impacts may occur. However, any new power plants that may be required for the load-following generation would be subject to local air district permitting and CEQA review. In addition, any increased operations at existing plants would be subject to air permit limitations. Thus, the proposed RES is not expected to disproportionately affect highly impacted communities or interfere with attaining or maintaining ambient air quality standards.

The RES may also result in non-air environmental impacts to aesthetics, agricultural resources, biological resources, cultural resources, geology and soil, hazardous materials, land use and housing, and water resources. The magnitude of these impacts is dependent upon the renewable technology and other site-specific conditions, and these impacts could range from none to potentially significant. Projects with significant impacts would require mitigation to reduce those impacts to acceptable levels. Appendix E of the Staff Report contains a full environmental assessment of the proposed RES.

Economic Impacts

The estimated incremental cost of electricity for meeting the proposed 33 percent RES, above the RPS 20 percent in 2020, is between $2.4 billion and $2.6 billion. The methodology used to estimate this cost in 2020 is consistent with the methodology used in the CPUC's 33 Percent Renewables Portfolio Standard Implementation Analysis Preliminary Results and the Scoping Plan. However, this is a conservative cost estimate because it assumes that renewable technology costs and performance do not change over time. As newer, better performing technologies come to the market and as demand increases for these new technologies, the costs should decrease over time.

The ARB does not oversee or have the authority to set energy prices. However, while working closely with the CPUC and the IOUs, staff was able to estimate the impact of a 33 percent RES using a Bill Impact Calculator (BIC). The BIC estimates the impact of the proposed RES on both residential and small commercial customer monthly bills. ARB staff estimates that in 2020 residential rate payers will experience a possible increase in monthly electricity bills in an amount of about three to ten percent compared to the RPS program in 2020. The actual amount will vary depending on factors such as electricity usage.

ARB staff also used the BIC to estimate monthly bill impacts for small commercial customers. On average, small businesses may experience a monthly bill increase equivalent to 0.2 percent of their revenue in 2020 compared to the RPS program. This estimate is based on current electricity usage and does not take into account any future energy efficiency improvements.

Staff estimates that the proposed regulation will shift capital from the conventional electricity sector to the construction, manufacturing, and fuel extraction sectors. This

results in increased output and employment in these industry sectors. Overall, given the size of the California economy the proposed RES will have a very small, slightly negative impact on the State's economy. Key economic indicators, such as gross State product and employment, show less than a 0.2 percent impact in 2020.

Staff's analysis projects increases of 8,000 to 10,000 permanent green jobs, but an overall slight net decrease in total job growth in California. When considering the impact of allowing out-of-state renewable resources, less than five percent of new green jobs occur outside California.

Public Process for RES Regulation Development

ARB staff collaborated closely with staff members of the CPUC, CEC, and CAISO in developing the RES regulation. Staff members of these agencies provided background information on the existing RPS program, conducted supporting research, commented on draft regulatory concepts and language, assisted with the development of analyses, and participated in public workshops hosted by ARB in support of the RES.

ARB staff held six public workshops and met individually with more than 35 separate retail sellers of electricity, affected parties, and stakeholders during the development of the proposed RES. ARB staff's public outreach efforts for the RES proposal included creating an RES webpage where information pertaining to the regulation development was posted, such as workshop notices and agendas, drafts of the regulation, staff analyses used in the development of specific sections of the regulation, and comment letters received in response to workshop solicitations. Staff reviewed and posted over 95 comment letters submitted by utilities and other stakeholder interests. In addition, an electronic list serve was created to notify stakeholders and interested parties of upcoming workshops and postings of new material to the webpage. Over 800 individuals or companies have subscribed to the RES list serve.

Evaluation of Alternatives

Staff evaluated two alternatives to the proposed regulation. One alternative was to not implement the RES, which would result in a 20 percent renewable energy target by 2020 under the current RPS. However, this "no action" or "no project" alternative would forego or delay the adoption of the proposed rulemaking. This alternative would rely on future State and/or federal legislative directives to increase the amount of renewable energy powering the California grid and further reduce GHG emissions from the electricity sector in California. This alternative was rejected as it would result in failure to make progress in reducing emissions of GHGs from the electricity sector as directed by Governor Schwarzenegger's Executive Order S-21-09, as well as failure to achieve the GHG reductions associated with a 33 percent renewable energy mix statewide by 2020, which was included in the Scoping Plan.

Staff evaluated one other regulatory alternative for meeting a 33 percent target by 2020, which would require regulated parties to procure renewable energy above 20 percent

from in-state renewable resources only. Staff used the RES Calculator to evaluate the projected incremental differences between the 20 percent RPS and this 33 percent RES alternative under two different load projections, similar to what was done with the analysis of the proposed regulation.

The analysis shows that in-state renewable generation results in identical GHG emission reductions and essentially identical criteria pollutant emissions. In addition, the analysis shows that slightly more green jobs are created within the State. However, this alternative requires more revenue, is less cost-effective, has higher monthly bill impacts for residential customers, has a slightly higher increase in electricity rates for small businesses in 2020, and has a slightly larger negative impact on California's overall economy. Consequently, this alternative results in no additional GHG emission reductions and has higher costs. Therefore, staff rejected this alternative.

Recommendation

ARB staff recommends that the Board approve the staff's proposal to require essentially all California electricity providers to use renewable energy to satisfy 33 percent of their retail sales by 2020. The proposed RES will result in the reduction of at least 12 $MMTCO_2E$ by 2020 and is consistent with the objectives of California's Climate Change Scoping Plan.

This Page Intentionally Left Blank

I. INTRODUCTION

This Staff Report presents the Air Resources Board's (ARB/Board) basis and rationale for the proposed regulation for the California Renewable Electricity Standard (RES). The RES would reduce emissions of greenhouse gases (GHG) by displacing the generation of electricity from fossil fuel sources that emit GHGs with renewable energy sources that have zero or very low GHG emissions. GHG reductions would be achieved by requiring retail sellers of electricity to ramp up the amount of renewable electricity provided to their California customers from 20 percent to 33 percent by 2020. Staff is proposing this regulation to assist California with achieving its mandate to reduce GHG emissions to 1990 levels by 2020. In addition, the RES is designed to reduce California's dependency on fossil fuel and promote clean energy and green technologies.

This chapter briefly describes the relationship between GHGs and climate change, the legislative and policy directives that pertain to GHG reductions and renewable energy production in California, and the public process used to develop the RES.

A. Greenhouse Gases and Climate Change

Climate change is already evident in the State and it is happening now. Local changes are consistent with the emerging evidence across the globe and are largely driven by human activities such as the burning of fossil fuels, transportation, and manufacturing processes. These activities release carbon dioxide and other GHGs into the atmosphere which trap heat that would otherwise escape into space. GHG emissions accumulate in the atmosphere and remain there for decades to centuries, further trapping heat and driving climate change.

California is the fifteenth largest emitter of GHGs on the planet, representing about two percent of the worldwide emissions. Carbon dioxide (CO_2) is the largest contributor to climate change. Other GHGs include methane, nitrous oxide, sulfur hexafluoride, hydrofluorocarbons, and perfluorocarbons.

Sea levels have risen by as much as seven inches along the California coast over the last century, increasing erosion and pressure on the State's infrastructure, water supplies, and natural resources. The State has also seen increased average temperatures, more extreme hot days, fewer cold nights, a lengthening of the growing season, shifts in the water cycle with less winter precipitation falling as snow, and both snowmelt and rainwater running off sooner in the year. These climate driven changes affect resources critical to the health and prosperity of California. For example, forest wildland fires are becoming more frequent and intense due to dry seasons that start earlier and end later. The State's water supply, already stressed under current demands and expected population growth, will shrink under even the most optimistic climate change

scenario. Almost half a million Californians, many without the means to adjust to expected impacts, will be at risk from sea level rise along bay and coastal areas.[1]

Recognizing the need to sharply cut GHG emissions to avoid future adverse impacts to the State's environment, public health, and economy, the California Legislature passed and Governor Schwarzenegger signed Assembly Bill (AB) 32 (Núñez, Ch. 488, Statutes of 2006). In the Findings and Declarations for the Global Warming Solutions Act of 2006 (AB 32), the Legislature found that:

> *"The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in quality and supply of water to the State from the Sierra snowpack, a rise in sea levels resulting in the displacement of thousands of coastal businesses and residences, damage to the marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases asthma, and other health-related problems."*

The Legislature further found that global warming would cause detrimental effects to some of the State's largest industries, including agriculture, winemaking, tourism, skiing, commercial and recreational fishing, forestry, and the adequacy of electrical power.

B. Legislative and Policy Directives Relating to Renewable Energy

In the last decade, California has implemented several policies to expand renewable energy production in the State and reduce GHG emissions from the electricity sector. These policies will assist the State with reducing its dependency on fossil fuel and transitioning to clean energy, and promoting green technologies. These policies are outlined below.

Senate Bill 1078[2] (Sher, Chapter 516, Statutes of 2002): This bill established California's Renewables Portfolio Standard (RPS) requiring retail sellers of electricity regulated by the California Public Utilities Commission (CPUC) to procure 20 percent of retail sales from renewable energy by 2017. These retail sellers include electrical corporations (also known as investor owned utilities or IOUs), community choice aggregators (CCAs), and electric service providers (ESPs). The local publicly owned electric utilities were encouraged, but not required, to meet the same goal. The bill delegated specific implementation roles to the California Energy Commission (CEC) and the CPUC.

Energy Action Plans I (2003)[3] **and II (2005)**[4]: In 2003, CEC, CPUC, and the Conservation Financing Authority (now defunct) adopted an Energy Action Plan to articulate a single, unified approach to meet California's electricity and natural gas needs. The Plan recommended accelerating the RPS deadline to 20 percent by 2010. The second Energy Action Plan, adopted in 2005 to reflect the policy

changes and actions of the ensuing two years, recommended an accelerated goal of 33 percent renewables by 2020.

Executive Order S-3-05[5] (2005): In June 2005, the Governor signed Executive Order (EO) S-3-05 calling for the State to reduce GHG emissions to 1990 levels by 2020 and to reduce emissions to 80 percent below 1990 levels by 2050. The 2020 goal was established to be an aggressive, but achievable, mid-term target and the 2050 goal represents the global reductions scientists believe are necessary to reach levels that will stabilize our climate.

Senate Bill 1368[6] (Perata, Chapter 598, Statutes of 2006): The CEC and CPUC jointly established limits on long-term investments by the State's retail sellers in baseload power plants that exceed an emissions performance standard (EPS). The EPS precludes California's retail sellers from making investments in, or using long term contracts to procure baseload electricity generation that emits more carbon dioxide than a combined cycle gas turbine. The EPS effectively prohibits the procurement of baseload energy from coal-fired power plants (unless they sequester CO_2) and other higher-emitting power plants.

Senate Bill 107[7] (Simitian, Chapter 464, Statutes of 2006): This bill modified California's RPS program by requiring retail sellers of electricity (IOUs, CCAs, and ESPs), to procure 20 percent of retail sales from renewable energy by 2010 as recommended in the *Energy Action Plan I*.

Executive Order S-14-08[8] (2008): In November 2008, the Governor signed EO S-14-08 that accelerated the RPS target to 33 percent renewable by 2020, as recommended in the *Energy Action Plan II*.

Assembly Bill 32[9] (Núñez, Ch. 488, Statutes of 2006): Assembly Bill (AB) 32, referred to as the California Global Warming Solutions Act of 2006, required the Board to develop a plan to reduce GHG emissions in California to 1990 levels by 2020, or about a 30 percent reduction from projected 2020 levels. Among other provisions, the plan must achieve the maximum technologically feasible and cost-effective reductions in GHG emissions from sources or categories of sources of GHGs by 2020.

Climate Change Scoping Plan[10] (2008): In December 2008, the Board approved the Climate Change Scoping Plan (Scoping Plan or Plan) as required per AB 32. This Plan sets forth a comprehensive reduction strategy that combines market-based regulatory approaches, other regulations, voluntary measures, fees, policies, and other programs to reduce California's GHG emissions to 1990 levels by 2020. The Plan identified electricity generation (which includes both in-state and out-of-state generation) as the second largest contributor to California's GHG emissions, with 23 percent of the State's total GHG emissions. The Scoping Plan identified a number of measures to reduce GHG emissions from California's electricity sector. In terms of GHG reductions,

the most significant of these measures was to implement the goals of Executive Order S-14-08, and achieve a 33 percent renewable energy by 2020.

Executive Order S-21-09[11] (2009): This EO, signed by the Governor on September 15, 2009, directed ARB, under its AB 32 authority, to adopt a regulation by July 31, 2010, consistent with the 33 percent renewable energy target established in Executive Order S-14-08. As specified in Executive Order S-21-09, the ARB:

1. May consider different approaches that would achieve the objectives of the Executive Order based on a thorough assessment of such factors as technical feasibility, system reliability, cost, GHG emissions, environmental protection or other relevant factors;

2. Shall work with the CPUC and the CEC to ensure that a regulation adopted under authority of AB 32 builds upon the RPS Program and regulates all California load serving entities, including investor-owned utilities, publicly-owned utilities, direct access providers and community choice aggregators;

3. May delegate to the CPUC and the CEC any policy development or program implementation responsibilities that would reduce duplication and improve consistency with other energy programs;

4. Shall consult with California Independent System Operator (CAISO) and other load balancing authorities on, among other aspects, impacts on reliability, renewable integration requirements and interactions with wholesale power markets in carrying out the provisions of the Executive Order; and

5. Shall establish the highest priority for those resources that provide the greatest environmental benefits with the least environmental costs and impacts on public health.

The proposed RES regulation satisfies the directive in Executive Order S-21-09. The proposed regulation builds upon the State's existing RPS program of 20 percent renewable energy by 2010 by requiring utilities and other load-serving entities to procure energy from additional renewable resources to meet a 33 percent renewable electricity standard by 2020. The proposed RES was developed in close collaboration with the staff of the CEC, CPUC, CAISO, and other balancing authorities as required by EO-S-21-09, and utilizes to the greatest extent practicable, the structure, provisions, policies, and implementation mechanisms that the CEC and CPUC established for the existing RPS program. Finally, the proposed RES will provide significant GHG reductions, which will assist the State with meeting its AB 32 requirements.

C. Public Process for Development of the RES

Public participation is an integral part of ARB's rulemaking process. Government Code section 11346.46 requires an agency proposing to adopt complex proposals or a large number of proposals to involve the public. ARB staff typically involves the public in workshops and other preliminary activities well before the start of the formal rulemaking process.

ARB staff's public outreach efforts for the RES proposal included creating an RES webpage where information pertaining to the regulation development was posted, including: workshop notices and agendas; drafts of the regulation; staff analyses used in the development of specific sections of the regulation; and comment letters received in response to workshop solicitations. Staff reviewed and posted over 95 comment letters submitted by utilities and other stakeholders. In addition, an electronic list serve was created to notify stakeholders and interested parties of upcoming workshops and postings of new material to the webpage. Over 1,000 individuals or companies have subscribed to the RES list serve.

Consistent with Governor Schwarzenegger's Executive Order S-21-09, ARB staff collaborated closely with staff members of the CPUC, CEC, and CAISO in developing the RES regulation. Staff members of these agencies provided information on the administrative requirements of the existing RPS program, conducted supporting research, commented on draft regulatory concepts and language, assisted with the development of analyses, and participated in public workshops hosted by ARB in support of the RES.

In developing the proposed regulation, ARB staff held six public workshops, as noted in Table I-1 below, and met individually with more than 45 separate utilities and stakeholder interests or groups.

Table I-1
Public Workshops Held During RES Development

Workshops	Date
First Workshop	October 30, 2009
Second Workshop	December 14, 2009
Third Workshop	February 2, 2010
Fourth Workshop	March 18, 2010
Fifth Workshop	April 5, 2010
Sixth Workshop	May 20, 2010

As part of its outreach efforts, ARB staff presented information about the proposed RES regulation at several interagency and interest-group sponsored

conferences or meetings. These included a Joint Energy Agency Action Plan Meeting hosted by the CPUC, the annual meeting of the International Colloquium on Environmentally Preferred Advanced Power Generation, the mid-year conference of the California Association of Sanitation Agencies, Long-view Committee of the California Environmental Dialogue, and a Home Rule Advisory Group meeting of the South Coast Air Quality Management District.

REFERENCES

[1] California Natural Resources, 2009. Executive Summary 2009 California Climate Adaptation Strategy, http://www.energy.ca.gov/2009publications/CNRA-1000-2009-027/CNRA-1000-2009-027-F-ES.PDF

[2] California State Senate, 2002. Senate Bill No. 1078 (Chapter 516), http://www.energy.ca.gov/portfolio/documents/SB1078.PDF

[3] California Energy Commission, California Public Utilities Commission, and Consumer Power and Conservation Financing Authority, 2003. Energy Action Plan, http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF

[4] California Energy Commission and California Public Utilities Commission, 2005. Energy Action Plan II: Implementation Roadmap for Energy Policies, http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF

[5] State of California, Office of the Governor, 2005. Executive Order S-3-05, http://www.dot.ca.gov/hq/energy/ExecOrderS-3-05.htm

[6] California State Senate, 2006. Senate Bill No. 1368 (Chapter 598), http://www.energy.ca.gov/emission_standards/documents/sb_1368_bill_20060929_chaptered.pdf

[7] California State Senate, 2006. Senate Bill No. 107 (Chapter 464), http://www.energy.ca.gov/portfolio/documents/sb_107_bill_20060926_chaptered.pdf

[8] State of California, Office of the Governor, 2008. Executive Order S-14-08, http://gov.ca.gov/executive-order/11072/

[9] California State Assembly, 2006. Assembly Bill No. 32 (Chapter 488), http://www.climatechange.ca.gov/publications/legislation/ab_32_bill_20060927_chaptered.pdf

[10] ARB, 2008. Climate Change Scoping Plan, http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf

[11] State of California, Office of the Governor, 2009. Executive Order S-21-09, http://gov.ca.gov/executive-order/13269

This Page Intentionally Left Blank

II. STATUTORY REQUIREMENTS

Assembly Bill 32 (AB 32) establishes criteria in Health and Safety Code section 38562 that apply to regulations adopted consistent with the Scoping Plan. Those criteria are summarized here (noted in italics) along with staff's assessment as to why the proposed regulatory action complies.

- *The State Board shall adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost effective greenhouse gas emission reduction, from sources or categories of sources.*

The proposal for the RES regulation was developed in consultation with affected parties in an open process through six public workshops, numerous industry-specific consultation meetings, and numerous telephone conferences. Draft regulatory concepts were modified through discussion and feedback during this process to ensure that least-cost methods to achieve reductions were proposed. Chapter I of this report provides details of staff outreach activities.

- *Design the regulations, including distribution of emissions allowances where appropriate, in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California, and encourages early action to reduce greenhouse gas emissions.*

Consistent with Governor Schwarzenegger's Executive Order S-21-09, the proposed regulation applies to all, but the very smallest, California load serving entities. The regulation was designed to utilize, to the greatest extent feasible, the implementation mechanisms that the CEC and CPUC have for the existing California Renewables Portfolio Standard (RPS) Program and to avoid duplicative reporting and compliance verification processes for regulated parties. The design of the regulation is performance-based and requires that all regulated parties meet the same percent renewables requirement (RES obligation).[a] The regulation has been designed with a compliance schedule that provides flexibility during the early years of the program through multi-year compliance intervals, but also ensures steady progress toward the 33 percent renewables requirement by establishing corresponding interim RES obligations. The regulation may encourage early compliance by allowing renewable energy credits (RECs) that are not used to meet a current RES obligation to be banked to meet a future RES obligation. The regulation also provides flexible REC trading options to achieve GHG reductions and increase the potential availability of renewable resources in the Western Electricity Coordinating Council (WECC).

- *Ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities.*

Generally, renewable generation produces less criteria pollutant and toxic emissions per unit of electricity output than the fossil-fuel generation it will displace. Therefore, the

[a] The RES obligation may vary for specific parties with large hydroelectric resources.

regulation is expected to provide an overall air quality benefit by reducing statewide emissions of criteria and toxic air pollutants. There is a potential for additional renewable generating facilities to be built in California and for existing fossil fuel-fired generating units that provide back-up power to variable renewable resources to modify operations. Some of these facilities may be located in low-income communities. It is expected that new facilities will trigger local permitting and environmental review. The magnitude of these impacts is dependent upon the renewable technology and other site-specific conditions. Projects with significant impacts would require mitigation to reduce those impacts to acceptable levels.

- *Ensure that entities that have voluntarily reduced their greenhouse gas emissions prior to the implementation of this section receive appropriate credit for early voluntary reductions.*

The proposed regulation contains provisions that allow POUs to claim credit under the RES, with limited restrictions, for self-certified resources claimed under the RPS program.

- *Ensure that activities undertaken pursuant to the regulations complement and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions.*

The proposed regulation is not expected to adversely affect federal or State ambient air quality standards. This issue has been analyzed and the results are provided within the environmental chapter of this report. Overall, staff expects a reduction in criteria and toxic air pollutants. Staff expects that some localized air impacts may occur in areas where new renewable generation facilities are sited, new transmission lines are constructed, and upgrades are made to existing distribution lines. These projects are expected to be subject to local permitting and environmental review. See Chapter IX (Environmental Impacts) for a detailed discussion of this issue.

- *Consider cost-effectiveness of these regulations.*

In developing the proposed regulation, the staff has considered the cost-effectiveness and determined that it would range from $196 to $198 per metric ton of carbon dioxide-equivalent emissions ($MTCO_2e$) reduced. See Chapter X (Economic Impacts) of this report for detailed information regarding cost-effectiveness.

- *Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health.*

From an overall perspective, the proposed regulation is expected to result in a net benefit for Californians by decreasing our dependence on fossil fuel-fired energy resources and reducing GHG, criteria air pollutant, and toxic air pollutant emissions

from the electricity sector. See Chapter IX (Environmental Impacts) for a detailed description.

- *Minimize the administrative burden of implementing and complying with these regulations.*

The administrative burden of complying with the proposed regulation has been minimized to the extent possible. The proposed regulation contains recordkeeping and reporting requirements for regulated parties that are necessary to ensure compliance. These requirements have been limited to only information that is necessary to demonstrate compliance. The proposed RES Program is designed to use, where possible, the current reporting, monitoring and verification, certification, and recordkeeping requirements, forms, and reports required by CEC and CPUC for the existing RPS program. See Chapter XII (Implementation and Enforcement) for a detailed discussion of the reporting requirements.

- *Minimize leakage*

Leakage occurs when State policy results in a reduction in GHG emissions within the State that is offset by an increase in GHG emissions outside California. Leakage under the RES could occur if a California retail seller buys unbundled RECs (RECs without the electricity), but the electricity is claimed as renewable in another state. In addition, leakage could occur if a California retail seller claims RES credit by purchasing RECs from an already existing renewable facility. RPS program requirements, which are subsumed by the proposed regulation, would limit these leakage scenarios – specifically, tracking of RECs in WREGIS and eligibility requirements for new out-of-state facilities.

First, RECs used for compliance with the proposed regulation must be registered in and tracked by WREGIS. WREGIS issues a uniquely numbered certificate for each MWh of electricity generated by a facility registered in the system and tracks the ownership of certificates as they are traded. The owner of the RECs retires the certificates in WREGIS for *only one* specific renewables program (e.g., the California RPS or the Oregon RPS) to avoid double counting and double claims. RECs used for compliance with the RES must be retired in WREGIS and may not be used for compliance with any other federal, state, or local program. However, a REC used for compliance with the California RPS would count toward compliance with the RES.

Second, to qualify for the RPS, out-of-state facilities must commence initial commercial operation on or after January 1, 2005. A facility that commenced operation prior to this date could qualify if the facility is part of a retail seller's existing baseline procurement portfolio as identified by the CPUC. This ensures that any additional renewable electricity requirement is met by *new* renewable generation. If RECs from an existing renewable facility were to be used to meet a California RES obligation, then that electricity would not displace existing fossil fuel-fired generation.

- *Consider the significance of the contribution of each source or category of sources to statewide emissions of greenhouse gases.*

The Scoping Plan states that electricity generation from central power plants and distributed generation systems were responsible for approximately one-quarter of all GHG emissions in California in 2004, or about 120 $MMTCO_2e$. This makes electricity production second only to transportation in terms of its contribution to California's carbon footprint. The projected reductions that will be achieved through implementation of the proposed regulation are equivalent to reducing about 12 to 13 $MMTCO_2e$ in 2020.

- *The greenhouse gas emission reductions achieved are real, permanent, quantifiable, verifiable, and enforceable by the State board.*

Real Reductions. Staff believes that the GHG emission reductions from increased renewables procurement would be real because they will be based on the actual procurement of RECs that represent the environmental attributes of renewable generation. RECs retired for compliance with the RES Program would be tracked by the WREGIS system. In addition, RECs used for compliance with the regulation must come from eligible renewable energy resources. These eligible resources must be certified by the CEC or the ARB.

Permanency. The proposed regulation would require the regulated parties to provide increasingly higher percentages of renewable generation until 33 percent is achieved in 2020 and thereafter. In order to ensure that the RES targets are met, a regulated party is required to permanently retire RECs tracked by the WREGIS system. By permanently retiring RECs, the GHG emission reductions are ensured to be permanent.

Quantification and Verification. Compliance with the proposed regulation is demonstrated through the acquisition and retirement of RECs. RECs must be tracked by WREGIS to satisfy the percent renewables requirements. The proposed regulation would require the regulated parties to maintain annual records of RECs (i.e., WREGIS certificates) retired and total retail electricity sales to end-use customers. Some additional information is required to demonstrate compliance over the interim compliance intervals. This documentation must be supplied to ARB via annual progress reports and compliance interval reports that would be used to verify the accuracy of the records. The annual reports sent to ARB will be used to estimate the annual GHG emission reductions from regulated parties. Using the reported information, megawatt-hours (MWh) of eligible generation would be converted to tons of GHG reductions using established GHG emission factors for each renewable energy technology to determine the GHG benefits from the use of renewables. The estimated GHG emissions and benefits will be made available to the public via the ARB's Internet website.

Enforceability. The regulation, as proposed, contains requirements which support enforcement efforts, including report submissions with data that can be verified for compliance purposes.

- *The reduction is in addition to any greenhouse gas emission reductions otherwise required by law or regulation, and any other greenhouse gas emission reductions that otherwise would occur.*

There is no federal regulation implementing a national renewable portfolio standard. Two Congressional bills, however, have been introduced, which would establish a federal-level combined efficiency and renewable electricity standard.

Existing State law established the California RPS, which requires retail sellers of electricity (electrical corporations {or investor owned utilities}, community choice aggregators, and electric service providers) to procure 20 percent of retail sales from renewable energy by 2010. The proposed regulation would not supersede the obligations that apply to these entities under the existing RPS Program. Rather, the proposed regulation would complement and build upon the RPS Program by increasing the percent renewables requirement to 33 percent. There is no duplication of regulatory requirements because a REC used for compliance with the California RPS would count toward compliance with the RES.

- *If applicable, the greenhouse gas emission reduction occurs over the same time period and is equivalent in amount to any direct emission reduction required pursuant to this division.*

This requirement does not apply to the proposed regulation because it achieves its emissions reductions as direct emissions.

- *The State board shall rely upon the best economic and scientific information and its assessment of existing and projected technological capabilities when adopting the regulations required by the law.*

ARB staff collaborated closely with the CPUC, CEC, and CAISO to ensure that the analyses used the most current data and that the regulatory provisions were based on a thorough assessment of factors such as technical feasibility, system reliability, cost, GHG emissions, and environmental protection.

Staff analyzed the incremental differences in cost and environmental impacts among program alternatives under two different load-demand conditions, representing the highest and lowest amounts of electricity demand that may be expected in 2020. In addition, staff compared the renewable energy mix in 2020 for the existing RPS Program to the proposed 33 percent RES in 2020.

- *For regulations including market-based compliance mechanisms, H&SC section 38570(b) requires the Board, to the extent feasible, to:*

  - *Consider the potential for direct, indirect, and cumulative emission impacts from these mechanisms, including localized impacts in communities that are already adversely impacted by air pollution;*
  - *Design such mechanisms to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants; and*
  - *Maximize additional environmental and economic benefits for California, as appropriate.*

Increasing the portion of electricity supplied from renewable resources will reduce GHG emissions by displacing electricity produced by existing fossil fuel-fired electrical generating facilities and reducing the need for new fossil-fueled generation facilities to be built. The regulation is expected to provide an overall air quality benefit by reducing statewide emissions of criteria and toxic air pollutants.

Some localized air impacts may occur in areas where new renewable generation facilities are sited. The criteria pollutant and toxic emissions associated with new renewable generation facilities will be subject to local air district permitting and California Environmental Quality Act (CEQA) requirements. If the new facility is located on federal land, it will also be subject to federal requirements under the National Environmental Policy Act (NEPA).

Because of the fluctuating nature of some renewable resources, such as wind and solar whose generation output varies depending on daily or seasonal changes, power from natural gas-fueled power plants will be needed to balance load demand when these resources are unable to operate (also known as shaping and firming). These occurrences reduce the benefits of the renewable resources and may also create some localized air impacts, depending on the type of load-following generation that is used. However, any new power plants that may be required for the load-following generation would be subject to local air district permitting CEQA requirements, and increased operations at existing plants would be subject to air permit limitations. Shaping and firming of out-of-state variable resources that are delivering power to the California grid may result in localized impacts outside of the State, and those impacts are expected to be addressed by applicable out-of-state regulatory programs.

ARB is committed to making the achievement of fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies an integral part of the proposed RES. As such, staff evaluated the proposed regulation to determine if it disproportionately affects highly impacted communities, or interferes with the attainment and maintenance of ambient air quality standards. Staff also considered overall societal benefits, such as creation of green jobs, diversification of energy resources, and energy security. As part of the RES analysis, staff used the proposed screening method for geographically representing emission densities, air quality exposure metrics, and

indicators of vulnerable populations, as an evaluation aide for already adversely impacted communities.

Also included in the environmental analysis is an examination of other potential environmental impacts on land use, water quality and use, biological, cultural, and visual resources, among others. Possible approaches to mitigate or minimize these effects are included in the analysis.

Under the existing RPS program, there is no assurance that the electricity ultimately delivered to California is derived from renewable resources. This is because delivery can occur anytime within the same calendar year and the delivered electricity may come from anywhere within the WECC from any type of generating facility. Continuing the RPS-program delivery requirement for bundled RECs provides no additional GHG reduction benefits, but does reduce compliance options. California's geographic distribution of renewable energy resources and transmission constraints results in some entities less able to meet the renewable energy obligation compared to others. By not limiting trading, entities that need RECs can potentially buy from those with excess RECs. Allowing unlimited, unbundled RECs in an expanded geographic area reduces the ability of any participant to exert market pressure. The proposed regulation's use of unbundled, undelivered RECs is expected to provide greater flexibility for the regulated parties to achieve the RES goals, and will likely lower compliance costs. This is especially true in the early years where permitting and construction of renewable projects and transmission has not yet been completed. Additionally, allowing the use of unbundled RECs, regardless of where they are generated in the WECC, will reduce GHG emissions by the same amount as a more limited approach.

This Page Intentionally Left Blank

III. OVERVIEW OF THE CALIFORNIA ELECTRICITY SECTOR

This chapter presents a broad overview of California's electricity sector by introducing the electrical transmission network and providing an overview of the key parties involved in electricity monitoring, delivery, and regulatory activities. This chapter is intended to provide context to the terminology and concepts discussed throughout the report.

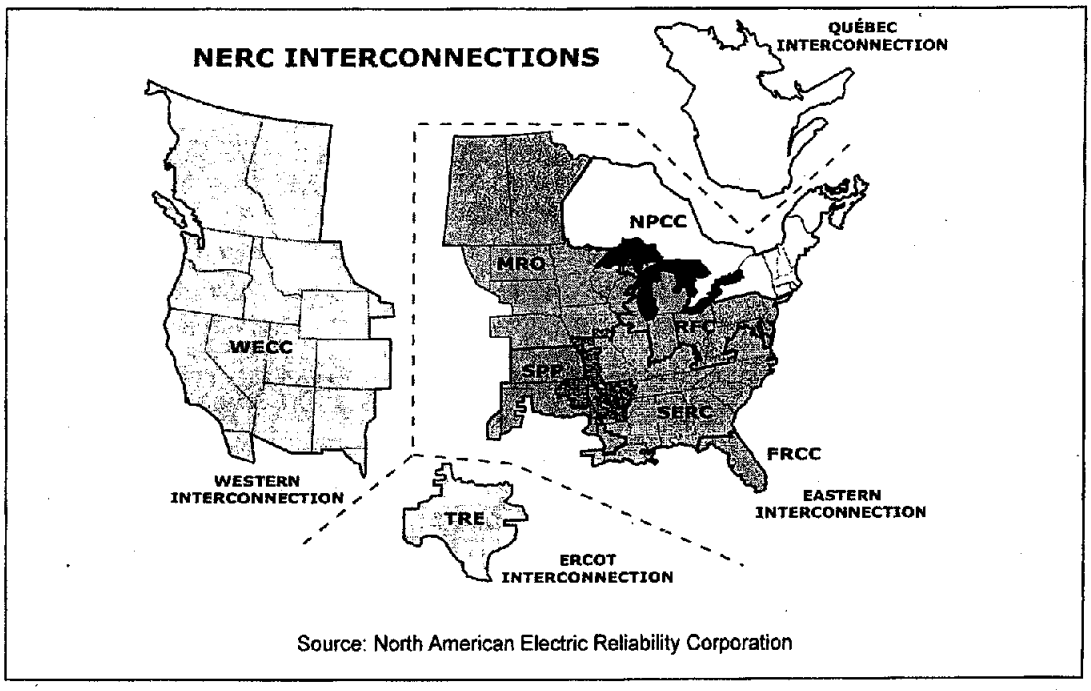
A. Electricity Transmission and Oversight

Electricity is a unique commodity that generally cannot be practically stored and must therefore be used right after it is generated at a power plant. High-voltage transmission lines are used to transmit electric power over relatively long distances, from a central power plant to substations, where the voltage is reduced. From the substation, distribution lines deliver power to customers. The high-voltage transmission lines are distinct from the local wiring between substations and customers, which are typically referred to as the electric distribution system. Transmission lines, when interconnected with each other, become high voltage transmission networks. In the United States, these are referred to as "power grids," or simply "grids." North America has three major grids: the Western Interconnection, the Texas Interconnection, and the Eastern Interconnection.[1]

Electricity follows the "path of least resistance;" it generally cannot be routed on a specific path from the location in which it is created to the place where it is consumed. This means generation and transmission operations must be monitored and controlled in real time to ensure a consistent and adequate flow of electricity through a broad interconnected system. This requires the cooperation and coordination of hundreds of electric industry participants. To handle this coordination for North America, reliability councils were established that operate the three North American grids. The North American Electric Reliability Corporation (NERC) is the independent, non-profit organization whose mission is to ensure the reliability of the grid in North America. NERC works closely with eight regional reliability councils.[2]

The Western Electricity Coordinating Council (WECC) is the regional entity responsible for coordinating and promoting grid reliability in the Western Interconnection. The WECC's service territory includes all of California and all or portions of 13 other states; the provinces of Alberta and British Columbia; and the northern portion of Baja California, Mexico. The WECC assures open transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members. The map in Figure III-1 shows the boundaries of the NERC interconnections as well as the eight regional reliability councils.[3]

Figure III-1
North American Power Grid and Reliability Organizations



Source: North American Electric Reliability Corporation

The WECC grid is divided into many smaller geographical areas – containing generation, transmission, and loads within metered boundaries – called balancing authority areas or control areas. The entity responsible for integrating electrical resource plans for the control area ahead of time, maintaining the control area's load-resource balance, and supporting the control area's interconnection frequency in real time is called a balancing authority. There are 10 balancing authorities located within California: the largest by far is the California Independent System Operator (CAISO). Others include the Los Angeles Department of Water and Power (LADWP), Sacramento Municipal Utility District (SMUD), Imperial Irrigation District, Turlock Irrigation District, PacifiCorp, Sierra Pacific Power, Nevada Power, Bonneville Power Administration, and Western Area Lower Colorado.[4]

B. Power Generation in California

1. Electric Utilities

California's energy ownership and delivery structure is complex and involves many different players. Entities that actually secure the physical electricity, transmission service, and related service from power plants to serve California retail customers are called load-serving entities (LSEs).[a] There are about 65 LSEs serving California customers. The five largest LSEs provide about 80 percent of the electricity consumed

[a] In the context of this report, the term LSE is being used generically to describe entities that provide electric power to end-use customers. It is not intended to refer to LSE as defined in section 380(j) of the Public Utilities Code. California Codes. Public Utilities Code Section 360-380.

in California. These are: Southern California Edison (SCE), Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric (SDG&E), Los Angeles Department of Water and Power (LADWP), and Sacramento Municipal Utility District (SMUD). The other 60 LSEs include four smaller investor-owned utilities (IOUs), 43 additional local publicly owned electric utilities (POUs), four electrical cooperatives, eight electricity service providers, a community aggregator, and a community choice aggregator. A discussion of each type of LSE follows.

a. Investor Owned Utilities (or Electrical Corporations)

There are seven Investor Owned Utilities (IOUs) serving customers in California. The three largest IOUs in California are PG&E, SCE, and SDG&E. These utilities provide close to 70 percent of California's electricity to retail customers. PG&E serves about 30 percent of statewide demand; SCE about 31 percent; and SDG&E about seven percent.[5]

The smaller California IOUs include Mountain Utilities, Bear Valley Electric Service, PacifiCorp, and Sierra Pacific Power Company. PacifiCorp and Sierra Pacific Power are multi-jurisdictional IOUs that serve customers inside and outside of California. Collectively, these IOUs serve less than one percent of California's electricity to retail customers.[5] While the California load served by PacifiCorp and Sierra Pacific Power is small in comparison to PG&E, SCE, and SDG&E, the total customer base served by these two utilities is actually comparable to SDG&E.[6] PacifiCorp serves about 1.7 million customers in six Western states.[7] Sierra Pacific Power serves about 1.2 million electric customers, primarily concentrated in the cities of Reno and Las Vegas, Nevada.[8,9]

b. Local Publicly Owned Electric Utilities

The local publicly owned electric utilities (POUs) in California are owned by their local customers and include municipal utility districts, public utility districts, joint power authorities, and irrigation districts. POUs collectively serve approximately 24 percent of California's electricity to retail customers.[10] POUs vary in size, ranging from the two largest in California, LADWP and SMUD (which, serve approximately 37 percent and 17 percent of total POU load, respectively),[5] to the smallest which may serve as few as 1,800 customers.[b] Fourteen of the smaller POUs pool resources or share in the development of resources, as part of the Northern California Power Agency (NCPA).[11] Out of the 45 POUs in California, the 14 largest provide approximately 90 percent of the total power served to retail customers by POUs.

c. Electrical Cooperatives

Electrical cooperatives are non-profit corporations which are owned by the members they serve. Cooperatives typically serve sparsely populated areas. There are four

[b] Based on estimated population of the City of Biggs, which operates its own electric utility. City of Biggs, 2009. Where the People Own the Water and the Power, http://www.biggs-ca.gov/

cooperatives serving California customers. These include the Surprise Valley Electrification Corporation and Plumas-Sierra Rural Electric Cooperative in Northeast California, Valley Electric Association which serves a few customers in Mono and Inyo Counties, and Anza Electric Cooperative in Southern California.[12,13] Collectively, their load represents less than one percent of statewide demand.[5]

d. Electric Service Providers

Electric Service Providers (ESPs) are non-utility entities that offer electric service to customers within the service territory of an electric utility. All ESPs must register with the CPUC. Examples of ESPs are Calpine Power, Commerce Energy, Sempra Energy, and Shell Energy.[14] In 2008, the ESPs served approximately eight percent of California's electricity to retail customers.

e. Community Aggregator

A community aggregator is a local government that purchases electricity for its end-use customers and does not own distribution facilities or transmission facilities. The local government must have rights to the power from the Magnolia Power Project located in Burbank, California. City of Cerritos is the only community aggregator in California.[15,16]

f. Community Choice Aggregators

Community choice aggregators (CCAs) were authorized by Assembly Bill 117 (Migden, Chapter 838, Statutes of 2002).[17] The CCA mechanism provides an opportunity for local government to purchase electricity on behalf of their residents and businesses. Unlike a municipal utility, a CCA does not own the transmission and delivery systems. The local entity only purchases the electricity; the delivery, metering, billing, operation, and maintenance of wires and poles remains the responsibility of the utility. There are several CCA plans in various stages of development. Marin Power Authority was the first operating CCA, with a plan to phase-in customers over the course of two phases: Phase I started in early May 2010 and Phase II is expected to commence in late spring or early summer of 2011.[18]

g. Other Government Agency Power Providers

Two other government agencies with load obligations include the California Department of Water Resources (DWR) and Western Area Power Administration (WAPA). The DWR is responsible for the operation and maintenance of the California State Water Project, which is a water storage and delivery system of 34 storage facilities, 20 pumping plants, four pumping-generating plants, five hydroelectric power plants, and approximately 700 miles of canals, tunnels, and pipelines. Its main purpose is to store water and distribute water to 29 urban and agricultural water agencies in Northern California, the San Francisco Bay Area, the San Joaquin Valley, the Central Coast, and Southern California. DWR provides electricity load to this Project, but is not obligated to serve other end-use customers. Because of the amount of energy needed to pump

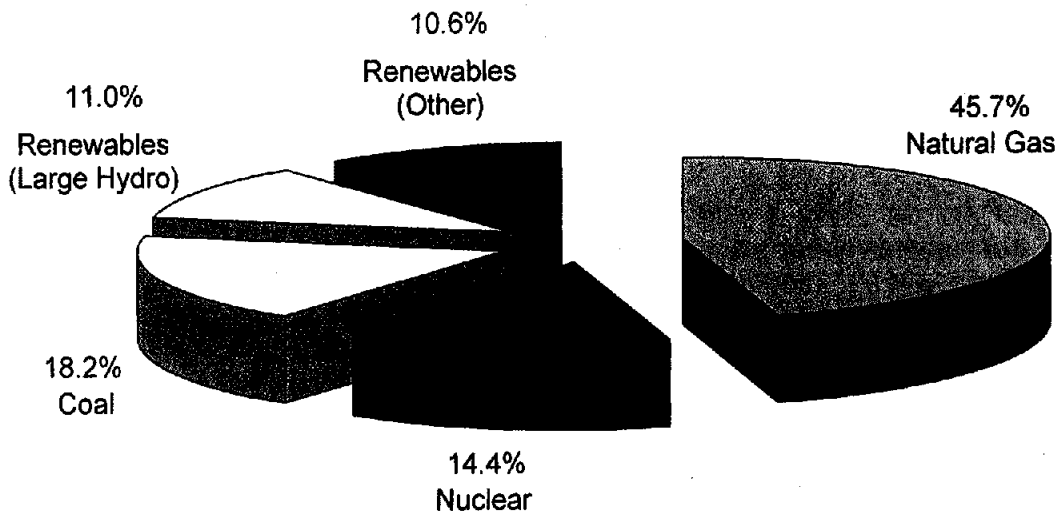
water, the State Water Project is one of the largest electricity users in California. The Project's nine hydroelectric power plants generate much of the electricity needed to move water, but DWR also purchases electricity from other utilities.[19] DWR makes their power available on the market and then purchases power off-peak to operate the facilities that move water to the water agencies. The load served by DWR represents about three percent of statewide demand.[5]

The WAPA is a wholesale power provider. It is a Federal agency under the United States (U.S.) Department of Energy that markets and transmits wholesale electrical power across 15 western states. This power is generated at 56 federal dams in 11 states plus the coal-fired Navajo Generating Station and is sold to federal and state agencies, rural electric cooperatives, municipalities, public utility districts, Native American tribes, and irrigation districts. These entities, in turn, provide retail electric services to consumers. The load served by WAPA represents slightly more than one percent of statewide demand.[20]

2. Power Plants

The total electricity demand in California in 2008 was nearly 286,000 gigawatt-hours (GWh), primarily in the commercial, residential, and industrial sectors. Roughly 70 percent of California's electricity is generated from power plants located in the State, which includes power plants that are physically outside of the State but owned by California utilities. The other 30 percent is imported electricity from the Pacific Northwest and the American Southwest. Figure III-2 shows the supply mix of California's electricity by type of generation in 2008.[21]

Figure III-2
California's Generation Mix (2008)[c]



Source: California Energy Commission, includes both in-state and out-of-state generation, with modification by ARB.

California's electricity supply is quite diverse, with electricity coming from fossil fuels; renewable resources such as wind, solar, biomass, and geothermal; distributed resources such as combined heat and power (CHP) and solar photovoltaic systems; large hydroelectric sources such as Shasta and Bonneville Dams; and nuclear facilities. This resource mix has changed over the years. In the late 1970s, petroleum was the fuel source for over half of the State's electricity. Today, renewable resources are used to produce over 20 percent of the State's electricity. Thirty-five percent of the State's generation is supplied by non-fossil fuel based resources. Of these, 11 percent is from large hydroelectric sources and another 11 percent comes from other renewable sources.[d] The fuel diversity in the electricity generation mix helps insulate California's economy from price shocks and supply disruptions, increases the reliability of the electricity system, and provides multiple environmental benefits. A detailed discussion of the air pollutant emissions from California's in-state power generating system is contained in Chapter IX (Environmental Impacts).

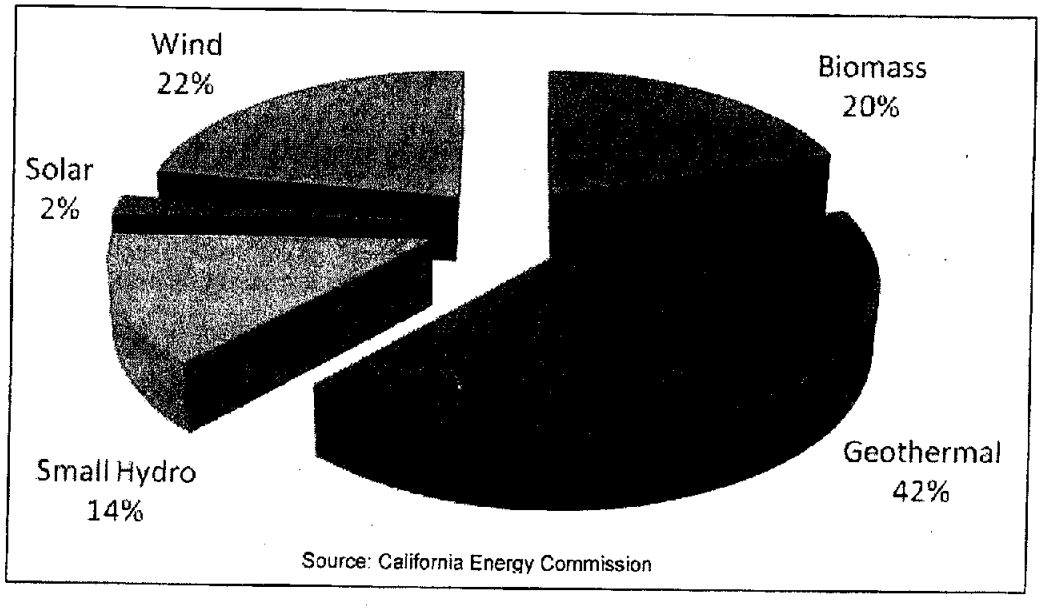
The exact makeup of California's electricity supply sources varies from year-to-year primarily as a result of two factors: the variability of hydroelectric resources and increasing amounts of renewable energy resources over time. The availability of energy

[c] ARB staff labeled "large hydro" as a renewable resource. Under the California RPS Program (see discussion in Chapter IV of the Staff Report), large hydro is not an eligible renewable energy resource. Percents in table based on California's 2008 total system generation (307,000 GWh) verses the California 2008 retail sales (286,000 GWh.) The two values differ because of energy loses from grid operations.
[d] Based on 2008 data, publicly available from the California Energy Commission.

from hydroelectric resources varies significantly depending upon precipitation patterns in California and the Pacific Northwest. A year in which there is below average rainfall or snowpack means that less electricity is produced from hydroelectric resources, and other generation resources (usually natural gas) must be increased.

Over the last three decades, the State has built one of the largest and most diverse renewable generation portfolios in the world. Large hydro supplied a little over 31,000 GWh in 2008, sources such as biomass, geothermal, small hydro, solar, and wind accounted for another 30,000 GWh.[22] A breakdown of renewable energy for each of these specific resource types is shown in Figure III-3.[23]

Figure III-3
California Renewable Energy Generation by Technology (2008)[e]



Source: California Energy Commission

As more renewable sources are added to California's generation mix, they tend to displace the need for more fossil generation, as the other two main conventional sources, nuclear and large hydroelectric, are neither growing nor declining in their average generation. However, conventional resources – natural gas, nuclear, coal, and large hydroelectric – will continue to be a large portion of the State's resource mix through the 2020 timeframe, even if a 33 percent renewable goal is implemented. Over the next ten years, wind and solar are expected to make up the majority of new renewable resources used to supply California's electricity needs.

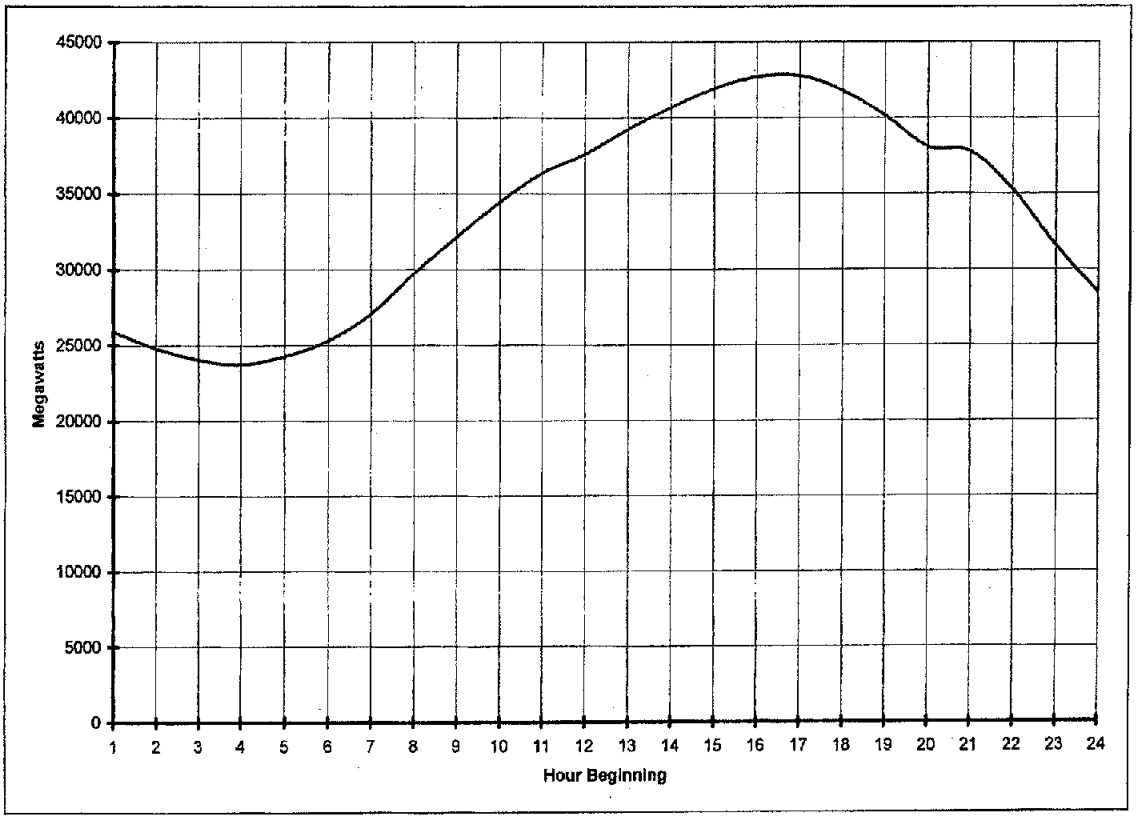
Electrical generating systems typically consist of several types of units to meet demand fluctuations – baseload, load following, and peak-load. Baseload plants are the production facilities used to meet some or all of a region's continuous energy demand and produce energy at a constant rate, usually at a lower cost relative to other

[e] Figure III-3 does not include large hydroelectric generation, because it is not an eligible renewable energy resource under the California RPS Program (see discussion in Chapter IV of the Staff Report).

productions facilities available to the system. Examples of baseload plants using nonrenewable fuels include natural gas-fired combined cycle turbines, nuclear, and coal-fired plants. Among the renewable energy sources, hydroelectric, biomass, and geothermal can provide baseload power. Baseload plants typically run at all times throughout the year except in the case of repairs or scheduled maintenance. Load following units ramp up and down with daily, hourly, and minute-to-minute fluctuations in demand. Examples of resources that can provide load following capacity include hydroelectric and natural gas-fired generation (combined-cycle turbines, simple-cycle turbines, and utility boilers). Peaking power plants, also known as peaker plants, are power plants that generally run only when there is a high demand (known as peak demand) for electricity such as on a hot summer day. The time that a peaker plant operates may be many hours on many days or as little as a few hours per year. In California, peaker plants are generally natural gas-fired turbines.

The load curve in Figure III-4 illustrates how the demand for electricity varies on a daily basis. Peak demand usually occurs in the late afternoon and early evening when the lights and air-conditioning of commercial buildings are still operating, and people are returning home to turn on their own appliances. While some renewable resources such as biomass and geothermal resources can provide baseload power, other resources such as wind and solar are intermittent and may not always be available to meet system needs during peak hours.

Figure III-4
CAISO System Daily Demand Curve[24]
(July 14, 2009)



C. California's Primary Energy Entities

There are three primary energy entities involved in the coordination and regulation of electricity in the State: the CAISO, the CPUC, and the CEC. The roles of these entities are briefly described below.

1. California Independent System Operator

As mentioned previously, the CAISO is one of ten balancing authorities in California. The CAISO control area includes more than 80 percent of the State's total electrical load. Therefore, the CAISO is responsible for ensuring the safe and reliable transportation of electricity on the power grid for the majority of the State. The CAISO neither buys nor sells electricity itself, but acts as a clearinghouse for daily market transactions and is the gatekeeper to power lines connecting California to neighboring states as well as Canada and Mexico. Another central function of the CAISO is to provide transparent information about the state of the system and prices. This information helps market participants assess the economics and manage the risks of wholesale power transactions and supply options.[25, 26]

2. California Public Utilities Commission

The CPUC regulates privately owned electric, natural gas, telecommunications, water, railroad, rail transit, and passenger transportation companies to ensure safe, reliable utility service and infrastructure at reasonable rates for California consumers. With respect to the electricity sector, the CPUC reviews and approves plans for utilities to purchase energy, establishes policies and rules for cost recovery for energy purchases, ensures that utilities maintain a set amount of energy above what they estimate they will need to serve their customers, and implements a long-term energy planning process. The CPUC also represents the interests of California's electric public utility consumers at the federal and regional level. The CPUC's efforts in transmission and wholesale market policies serve to advance California's electric system and market functions and promote California's environmental initiatives while ensuring fair utility rates for consumers.[27]

3. California Energy Commission

The CEC is the State's primary energy policy and planning agency. Its responsibilities include forecasting future energy needs and maintaining historical energy data; licensing large thermal power plants; promoting energy efficiency by setting State appliance and building efficiency standards and working with local governments to enforce those standards; supporting public interest energy research to advance energy science and technology; supporting renewable energy by providing market support to existing, new, and emerging renewable technologies; implementing the State's Alternative and Renewable Fuel and Vehicle Technology Program; and planning for and directing State response to energy emergencies.[28]

D. Air Resources Board's Role in the Electricity Sector

ARB is the State agency charged with coordinating efforts to attain and maintain federal and State ambient air quality standards and comply with the requirements of the federal Clean Air Act. In this role, ARB is empowered to do such acts as may be necessary for the proper execution of these powers and duties and, therefore, has oversight authority over local actions. The ARB is typically an informal participant in the evaluation and approval process for permitting new power plants and making modifications to existing power plants. Consistent with ARB's overall responsibilities, ARB staff follows power plant permitting proceedings and functions as a resource to the local air pollution control and air quality management district (local air district or district) and CEC staff. ARB staff also provides comments to the CEC and districts, as necessary, to reflect policies on best available control technology (BACT) and ensure power plants will be constructed and operated in compliance with all applicable laws, ordinances, regulations, and standards.

Power plants belong to a category of pollutant-emitting equipment known as stationary sources. The authority to regulate air pollutant emissions from stationary sources lies with California's 35 local air districts. The districts adopt and enforce emission

standards for power plants and other sources, consistent with their forward-looking plans for meeting the ambient air quality standards. As noted previously, the CEC has the authority to license large thermal power plants (≥50 MW). The districts participate in the CEC's siting process by reviewing applications and issuing permits, which are incorporated into the CEC's license.

With respect to GHGs, ARB is the lead agency for implementing Assembly Bill 32 (AB 32). The Scoping Plan outlines the State strategy to reduce GHG emissions consistent with AB 32 and includes measures that apply to the electricity sector. In addition to achieving a 33 percent renewables standard, other measures include increasing energy efficiency programs to reduce demand on the grid; increasing combined heat and power generation; reducing sulfur hexafluoride (SF_6) emissions from electricity transmission and distribution equipment; and conducting energy efficiency and co-benefits audits of large industrial sources, which includes certain power plants.

E. Federal Agency Involvement in Electricity Activities

The Federal Energy Regulatory Commission (FERC or Commission) is an independent regulatory agency within the U.S. Department of Energy. The Commission's purpose is to protect the public and energy customers by ensuring that regulated energy companies are acting within the law. FERC is responsible for: regulating the interstate transmission of natural gas, oil, and electricity; regulating the wholesale sale of electricity; licensing and inspecting hydroelectric projects; approving the construction of interstate natural gas pipelines, storage facilities, and liquefied natural gas terminals; monitoring energy markets and companies to protect customers from market manipulation and higher prices; and resolving disputes between energy companies, other organizations, and the public. Many areas outside of FERC's jurisdictional responsibility are dealt with by state public utility commissions, such as regulation of retail electricity and natural gas sales to consumers and approval of the physical construction of electric generating facilities. In California, these duties lie with the CPUC and CEC, respectively.[29,30]

REFERENCES

[1] U.S. Energy Information Administration, 2003. Electricity Transmission Fact Sheet, http://www.eia.doe.gov/cneaf/electricity/page/fact_sheets/transmission.html

[2] North American Electric Reliability Corporation, 2010. About NERC: Understanding the Grid, http://www.nerc.com/page.php?cid=1|15

[3] North American Electric Reliability Corporation, 2010. About NERC: Key Players – Regional Entities, http://www.nerc.com/page.php?cid=1|9|119

[4] California Energy Commission, 2010. California Balancing Authority Areas (Control Areas) map, http://www.energy.ca.gov/maps/ISO_NON-ISO_SERVICE_AREAS.PDF

[5] California Energy Commission, 2007. California Energy Consumption Database: Electricity Consumption by Entity, http://www.ecdms.energy.ca.gov/elecbyutil.aspx

[6] San Diego Gas & Electric Company, 1998-2010. Our Service Territory, http://www.sdge.com/aboutus/serviceTerritory.shtml

[7] PacifiCorp, 2009. Just the Facts, http://www.pacificorp.com/content/dam/pacificorp/doc/About_Us/Company_Overview/Just_The_Facts_PacifiCorp.pdf

[8] NVEnergy, 2008. Power Facts, http://www.nvenergy.com/company/facts.cfm

[9] NVEnergy, 2010. Service Territory, http://www.nvenergy.com/company/territory.cfm

[10] California Energy Commission, 2009. 2009 Integrated Energy Policy Report, http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF

[11] Northern California Power Agency. NCPA Members: Roster, http://www.ncpa.com/about-us/3.html

[12] Golden State Power Cooperative, 2003. About Us, http://www.gspower.org/about.html

[13] Valley Electric Association. Valley Electric Service Districts Map, http://www.vea.coop/images/Service-Districts-large.jpg

[14] California Public Utilities Commission, 2010. Registered Electric Service Providers, http://docs.cpuc.ca.gov/published/ESP_Lists/esp_udc.htm

[15] California State Assembly, 2002. Assembly Bill No 80 Chapter 837, http://info.sen.ca.gov/pub/01-02/bill/asm/ab_0051-0100/ab_80_bill_20020924_chaptered.pdf

[16] California Energy Commission, 2008. Progress Report on Resource Adequacy Among Publicly Owned Load-Serving Entities in California, Final Report, http://www.energy.ca.gov/2007publications/CEC-200-2007-016/CEC-200-2007-016-SF.PDF

[17] California State Assembly, 2002. Assembly Bill No. 117 Chapter 838, http://www.communitychoice.info/_pdf/ab_117_bill_20020924_chaptered.pdf

[18] Marin Clean Energy, 2010. Frequently Asked Questions, http://marincleanenergy.info/MCE_FAQ.cfm

[19] California Department of Water Resources, 2008. California's State Water Project brochure, http://www.water.ca.gov/recreation/brochures/pdf/swp.pdf

[20] Western Area Power Administration. About Western, http://www.wapa.gov/about/default.htm

[21] California Energy Commission, 2009. 2009 Integrated Energy Policy Report, http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF

[22] ARB, 2008. Climate Change Scoping Plan Appendices, Volume I: Supporting Documents and Measure Detail, December 2008, Appendix C, Electricity and Natural Gas (Pages C-87 to C-89), http://www.arb.ca.gov/cc/scopingplan/document/appendices_volume1.pdf

[23] California Energy Commission, 2010. Energy Almanac – California Electricity Sector Overview, http://energyalmanac.ca.gov/electricity/overview.html

[24] California Independent System Operator, 2010. OASIS: Open Access Same-time Information System, http://oasis.caiso.com/mrtu-oasis/?doframe=true&serverurl=http%3a%2f%2ffrptp09%2eoa%2ecaiso%2ecom%3a8000&volume=OASIS

[25] California Independent System Operator, 2007. Corporate Brochure: More Power to You, http://www.caiso.com/1bc3/1bc380bf45050.pdf

[26] California Independent System Operator. Information Kit: Guardian of the Grid, http://www.caiso.com/1c28/1c28acdd2a170.pdf

[27] California Public Utilities Commission, 2010. About Us, http://www.cpuc.ca.gov/PUC/aboutus/

[28] California Energy Commission, 2009. About the Commission, http://www.energy.ca.gov/commission/index.html

[29] Federal Energy Regulatory Commission, 2009. About FERC: What FERC Does, http://www.ferc.gov/about/ferc-does.asp

[30] Federal Energy Regulatory Commission, 2010. Student's Corner: What is FERC?, http://www.ferc.gov/students/whatisferc/whatisferc.htm

IV. OTHER RENEWABLE ENERGY ACTIVITIES

This chapter provides an overview of the existing programs, initiatives, and studies related to the advancement, evaluation, and management of renewable energy in California. A more detailed discussion of how the specific requirements of these activities interface with the proposed regulation is provided in Chapter V (Technology Assessment), Chapter VI (Renewable Energy Credits), and Chapter VII (Regulatory Design Assessment).

It should be noted that this chapter is not a comprehensive summary of all State activities related to the advancement of renewable generation or of activities directed at reducing the grid delivered electricity demand such as energy efficiency, combined heat and power, and distributed generation. A description of those programs can be found in other existing State reports and program Internet websites, such as the California Energy Commission's (CEC) website[a] or the ARB's Scoping Plan website.[b]

A. California Renewables Portfolio Standard

The California Renewables Portfolio Standard (RPS), originally established in 2002 under Senate Bill 1078 and accelerated in 2006 under Senate Bill 107, requires retail sellers of electricity regulated by the CPUC to increase the amount of renewable energy they procure until 20 percent of their retail sales are served with renewable resources. Retail sellers of electricity are required to meet this 20 percent level by December 31, 2010, and maintain the 20 percent indefinitely. The RPS applies to large and small investor owned utilities (IOUs), multi-jurisdictional utilities, electric service providers, and community choice aggregators. State law also requires local publicly owned electric utilities (POUs) to expand their use of renewable generation, but gives them flexibility in developing specific targets and timelines.

1. Overview of the RPS Program

The RPS program is collaboratively implemented by the CEC and the CPUC. The CEC is responsible for certifying renewable facilities as eligible for the RPS and operating the accounting system to track and verify RPS compliance. The CPUC is responsible for determining annual procurement targets, reviewing and approving each utility's renewable energy procurement plan, reviewing contracts for RPS-eligible energy, and ensuring compliance.

Procurement from a renewable facility cannot be counted toward a load serving entity's RPS obligation unless that facility has been certified as RPS-eligible by the CEC, and the facility's energy production has been tracked through WREGIS. WREGIS is an independent, renewable energy tracking system for the region covered by the WECC, and must be used to satisfy California's RPS tracking requirements. WREGIS tracks renewable energy generation from generation units that register in the system.

---

[a] California Energy Commission: http://www.energy.ca.gov
[b] Scoping Plan: http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm

WREGIS issues a certificate for each REC that represents one MWh of renewable energy. A WREGIS Certificate, and therefore the underlying REC, can be transferred and traded, but it must be retired in WREGIS before it can be counted toward the RPS.

2. Renewable Energy Credits (RECs)

As indicated previously, the RPS requires utilities to demonstrate compliance with the RPS program through the use of RECs. All renewable-based electricity generators produce two distinct products: physical electricity and RECs. A REC represents the right to claim the environmental attributes and benefits of renewable electricity generation.[c] At the point of generation, both product components can be sold together or separately, as a "bundled" or "unbundled" product. An unbundled REC can be sold to one entity, while the underlying physical electricity associated with a renewable generation source is delivered to another entity. See Chapter VI (Renewable Energy Credits) for more information on RECs.[1]

3. The CPUCs Tradable REC (TREC) Decision

The RPS program has allowed the procurement of bundled electricity and RECs to be used for RPS compliance since Senate Bill 1078 was enacted. The CPUC was given the authority in Senate Bill 107 to allow REC-only contracts to also count for RPS compliance. On March 16, 2010, the CPUC released a Decision allowing the use of unbundled RECs (termed tradable RECs or TRECs) to meet a portion of a utility's RPS obligation. The Decision set a temporary limit on TRECs for the three largest IOUs[d] to no more than 25 percent of a utility's annual procurement obligation and a price cap at $50 per TREC. Both of these limits would sunset at the end of 2011. For the small IOU utilities, the CPUC included no limits on the quantity of TRECs that could be used for compliance or the price paid for the TRECs. On May 10, 2010, this Decision was stayed pending further evaluation by the CPUC. See Chapter VI (Renewable Energy Credits) for more information on the CPUC's Decision and TRECs.

4. Certification of RPS-Eligible Renewable Generators

Any facility that generates electricity to count toward a retail seller's RPS obligation must certify the facility through the CEC. This section provides an overview of the requirements a facility must meet to be certified as RPS-eligible. A more complete discussion of eligibility requirements can be found in CEC's Renewables Portfolio Standard Eligibility Guidebook (Guidebook).[e]

---

[c] See CPUC Decision (D.) 08-08-028 that defines a REC for RPS compliance: http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/86954.pdf

[d] Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E).

[e] The Guidebook can be found at: http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF

A facility can qualify for the RPS if it uses an eligible renewable resource or fuel, satisfies resource-specific criteria, and is either located within the State or satisfies applicable requirements for out-of-state facilities. Facilities that have their first point of interconnection to the WECC transmission system within the State are considered to be in-state facilities. Out-of-state facilities that are not interconnected to the WECC transmission system are not eligible for the RPS.

Renewable resources or fuels eligible for the RPS program include:

- Biodiesel
- Biogas Injected into Natural Gas Pipeline
- Biomass
- Conduit hydroelectric
- Digester gas
- Fuel cells using renewable fuels
- Geothermal
- Incremental hydroelectric generation from efficiency improvements
- Landfill gas
- Municipal solid waste
- Ocean wave, ocean thermal, and tidal current
- Photovoltaic
- Small hydroelectric (30 MW or less)
- Solar thermal electric
- Wind

A description of each of these categories can be found in Chapter V (Technology Assessment).

CEC's Guidebook specifies conditions and limitations for each resource or fuel type, such as allowable feedstock for biodiesel and biogas and initial operating dates for small hydroelectric facilities. Some types of resources, such as biofuel and hydroelectric facilities, require supplemental information for certification. Specific criteria for each fuel type or resource can be found in the Guidebook.

Facilities that are located out-of-state and have their first point of interconnection to the WECC transmission system outside the State must meet the following additional requirements:

- must be connected to the WECC transmission system;
- generally must have began operating after January 1, 2005;
- not cause or contribute to any violation of a California environmental quality standard or other applicable requirements within California, such as an ambient air quality standard; and
- if located outside the United States, be developed and operated in a manner that is as protective of the environment as would a similar facility located in California.

The creation of an RPS-eligible REC demonstrates that the renewable energy has been created. However, CEC rules also require proof that an equivalent amount of energy was delivered to California before the REC from an RPS-eligible facility can be counted for compliance with the RPS. For renewable energy generated within California or delivered to an in-state market hub, the energy is deemed delivered.

To count generation from RPS-eligible out-of-state facilities toward the RPS, the following delivery requirements must be met. The renewable generator (the seller) and the buyer (utility, procurement entity, or third party) must enter into a power purchase agreement, and the buyer must demonstrate that an amount of energy equal to the MWh represented by the WREGIS-certificate was delivered to California within the same calendar year that the renewable energy was generated. The electricity delivered into California could come from anywhere within the WECC outside of California from any type of generating facility.[2] Delivery is verified through NERC e-tags "matched" with RPS-eligible facilities as specified in the Energy Commission's RPS eligibility guidebook.

As of April 2010, CEC has certified over 600 facilities as RPS-eligible. A list of current RPS-eligible generators can be found at CEC's RPS webpage.[f]

5. Procurement Process for RPS

Retail sellers can either build their own eligible renewable energy generation facility or contract with eligible facilities for their energy and RECs to be delivered to California to comply with the RPS program. CPUC establishes annual RPS targets for each retail seller, as well as reviews the three large utilities' renewable energy procurement plans. The CPUC ultimately determines final compliance by reviewing the amount of RECs retired in WREGIS and comparing this to the quantity of the utility's retail sales. See Chapter VI (Renewable Energy Credits) for more information on this process.

6. RPS Reporting and Compliance

LSE's must periodically report progress in achieving their RPS targets. RPS compliance reports are filed with the CPUC on March 1st and August 1st of each year, with the opportunity to supplement or amend the March filing by May 1st of that year. The reports must include actual and forecasted procurement information including total RPS eligible procurement by contract (existing/signed, short-listed/under negotiation/pending approval, and future contracts), RPS eligible procurement by resource type, and retail sales. The reports must also include detailed compliance information including incremental procurement target deferrals, earmarking, and banking, together with annual procurement deficits or potential penalties, if any.

[f] California's Renewables Portfolio Standard (RPS) Eligible Facilities: http://www.energy.ca.gov/portfolio/documents/list_RPS_certified.html

The CEC is responsible for verifying RPS procurement claims. The CEC describes its findings of those claims in an RPS procurement verification report. Within 30 days after the CEC approves an RPS procurement verification report, LSEs must submit RPS compliance reports to the CPUC, which use the CEC verified data. The CPUC then uses the verified RPS compliance reports to make a determination of compliance with the RPS program. In addition to the RPS compliance reports, the large investor owned utilities (IOUs) are required to file project development status reports on March 1st and August 1st each year, which describe development milestones, including site control, permitting status, project financing status, interconnection progress, and transmission.

7. Status of Utility Renewables Procurement

According to the CPUC, the three largest IOUs collectively served 15 percent of their 2009 retail electricity sales with renewable power.[3] Under the RPS program, retail sellers are allowed to carry, for up to three years, procurement deficits greater than 25 percent of that year's incremental procurement target (IPT) (including deficits larger than 100 percent of the IPT) without penalty if they can demonstrated one of the following:

- Insufficient response to the RPS solicitation;
- Contracts already executed will provide future deliveries sufficient to satisfy current year deficits;
- Inadequate public goods funds to cover above-market renewable contract costs; and
- Seller non-performance.

Shortfalls in excess of 25 percent of the IPT are also permitted upon a persuasive showing of lack of effective competition, that a deferral would promote ratepayer interests, but still satisfy the overall procurement objectives of the RPS program, or upon showing of good cause.[4]

ARB staff estimates that the POUs collectively served 19 percent of their 2009 retail electricity sales with renewable power. The percent renewables represents the POUs renewable power in 2009 as reported in the POUs resource adequacy plans submitted to CEC for RPS compliance. (Refer to Chapter VII for more discussion on the types of resources claimed by POUs under the RPS, which include resources other than those eligible for CEC certification.) If only the POUs' CEC-certified resources were considered, they would collectively have served 16 percent of their 2009 retail electricity sales with renewable power.

B. Out-of-State Renewable Programs

Nationwide, 29 states and the District of Columbia have renewable portfolio standards. Six other states have nonbinding, voluntary renewable energy goals. Within the WECC

region outside California, eight states have adopted their own mandatory renewable programs, with varying percent renewables requirements and compliance dates.

Table IV-1 summarizes the status and basic requirements of out-of-state renewable programs, as they were established as of March 2010 for states in the U.S. and November 9, 2007, for the Canadian provinces and Baja California. This table provides a broad picture of the programs and does not capture all of the individual program nuances that may exist, such as interim compliance standards, different requirements for new versus existing facilities, different requirements for investor-owned utilities versus publicly owned utilities, and limitations on trading of renewable energy credits (RECs). See Chapter VII, Regulatory Design Assessment, for more information on out-of-state renewable energy programs.

Table IV-1
Overview of Renewable Programs in North America[5,6]

State	Renewable Target	Compliance Date	REC Trading
Arizona	***15%***	***2025***	***Yes***
California	***20%***	***2010***	***Yes***
Colorado	***30%***	***2020***	***Yes***
Connecticut	23%	2020	Yes
Delaware	20%	2020	Yes
District of Columbia	20%	2020	Yes
Hawaii	40%	2030	No
Illinois	25%	2025	Yes
Iowa	105 MW	Not specified	Yes
Kansas	20%	2020	Yes
Maine	40%	2017	Yes
Maryland	20%	2022	Yes
Massachusetts	22.1%	2020	Yes
Michigan	10%	2015	Yes
Minnesota	25%	2025	Yes
Missouri	15%	2021	Yes
Montana	***15%***	***2015***	***Yes***
Nevada	***25%***	***2025***	***Yes***
New Hampshire	23.8%	2025	Yes
New Jersey	22.5%	2021	Yes
New Mexico	***20%***	***2020***	***Yes***
New York	29%	2015	No (Under discussion)
North Carolina	12.5%	2021	Yes
North Dakota*	10%	2015	Yes
Ohio	25%	2025	Yes
Oregon	***25%***	***2025***	***Yes***
Pennsylvania	18%	2021	Yes
Rhode Island	16%	2020	Yes
South Dakota*	***10%***	***2015***	***Yes***
Texas	***5,880 MW***	***2015***	***Yes***
Utah*	***20%***	***2025***	***Yes***
Vermont*	20%	2017	Not applicable
Virginia*	15%	2025	Yes
West Virginia*	25%	2025	Yes
Washington	***15%***	***2020***	***Yes***
Wisconsin	10%	2015	Yes
Alberta*	***15.5%***	***2020***	***No information***
British Columbia*	***13.4%***	***2020***	***No information***
Baja California	***No RPS***	***No RPS***	***No RPS***

Bold italics indicate a state or territory that in whole, or in part, is located within the WECC.
An asterisk (*) indicates a state or territory with a voluntary goal for adopting renewable energy instead of portfolio standards with binding targets.

C. Federal Renewable Portfolio Standard

Two Congressional bills are in development, which would establish a federal-level renewable portfolio standard. House of Representatives 2454 (Waxman), the American Clean Energy and Security Act of 2009, establishes a combined efficiency and renewable electricity standard that requires each retail electricity supplier selling four million MWh or more of electricity to consumers to supply an increasing percentage of its demand each year from a combination of electricity savings and renewable resources (6 percent in 2012 through 2013, 9.5 percent in 2014 through 2015, 13 percent in 2016 through 2017, 16.5 percent in 2018 through 2019, and 20 percent in 2020 through 2039). FERC would establish regulations to implement the Waxman Bill and would be tasked to incorporate the best practices of existing state and tribal renewable electricity programs and provide for the issuance, tracking, verification, and identification of RECs.

Senate Bill 1462 (Bingaman), the American Clean Energy Leadership Act of 2009, establishes a combined efficiency and renewable electricity standard that requires each retail electricity supplier that annually sells four million MWh or more of electricity to consumers to supply a specified percentage of its demand each year from a combination of electricity savings and renewable resources. The required percentages are as follows: 3 percent in 2011 through 2013, 6 percent in 2014 through 2016, 9 percent in 2017 through 2018, 12 percent in 2019 through 2020, and 15 percent from 2021 through 2039. Efficiency measures would be allowed to satisfy a percentage of a utility's renewables requirement. The U.S. Department of Energy would be required to establish a REC trading program and an energy efficiency credit trading program, under which utilities could submit credits to comply with the standards.

D. Energy Agency Activities for 33 Percent Renewables Portfolio Standard

Governor Schwarzenegger's signing of Executive Order S-14-08 in November 2008 established the 33 percent renewables target for California. This signing prompted State energy agencies to consider the target in all regulatory proceedings, including siting, permitting, and procurement for renewable energy power plants and transmission lines. Of primary concern was the need to determine what it would take, in terms of cost, risk, and timing, to achieve a 33 percent RPS. Both CPUC and CAISO commenced studies to answer these questions. Sections of the studies related to a 33 percent RPS are described briefly below, in Chapter V (Technology Assessment) and in Appendix B (Supporting Documentation for Technology Assessment).

1. CPUC 33 Percent Renewables Portfolio Standard Implementation Analysis

In June 2009, the CPUC released a preliminary implementation analysis for a 33 percent RPS by 2020, conducted within the CPUC's Long Term Procurement Plan proceeding. The analysis examined several resource mix scenarios and implementation pathways, including electricity cost comparisons and plausible goal

timelines for each scenario. The study examined a plausible resource portfolio or 33 percent RPS reference case as well as other cases representing extremes of various procurement strategies, including a high wind case, a high out-of-state wind delivery case, and a high distributed generation case. The report did not recommend a preferred strategy on how to reach a 33 percent RPS, but rather provided an analytical framework to help inform policymakers who would be designing a 33 percent RPS program for California.[7]

2. CAISO 33 Percent Renewables Portfolio Standard Operational Study

The CAISO has completed simulation studies to evaluate the operational requirements associated with a 20 percent RPS, and is currently conducting a study to assess the integration costs and operational needs necessary to integrate a 33 percent RPS. The study analyzes the same resource cases as were developed in the CPUC's June 2009 *33 % Renewables Portfolio Standard Implementation Analysis Preliminary Results*.

E. Electricity Transmission Activities

California has adopted energy policies that require substantial increases in the generation of electricity from renewable resources. To deliver power from the new generation, improvements are needed in the State's electric transmission infrastructure. ARB staff's summary of results from these initiatives is discussed in Appendix B (Supporting Documentation for Technology Assessment).

1. Renewable Energy Transmission Initiative

The Renewable Energy Transmission Initiative (RETI) is a joint effort among the CPUC, CEC, CAISO, investor-owned utilities, and public utilities. RETI was established in 2007 to bring together all of the renewable transmission and generation stakeholders in the State to participate in a consensus-based process to identify, plan, and establish a rigorous analytical basis for regulatory approvals of the next major transmission projects needed to access renewable resources in California and adjacent areas. RETI is assessing competitive renewable energy zones (CREZ) that can provide electricity to California consumers by 2020. The CREZ are zones that can be developed in the most cost-effective and environmentally benign manner. RETI will prepare detailed transmission plans for those zones identified for development.[8] RETI's work is organized into three phases. Phase 1, which is already complete, identified and ranked CREZs. The final reports (Phase 1A and Phase 1B) were released in May 2008 and December 2008. Phase 2, which is partially complete, is refining the CREZ analysis for priority zones and developing a conceptual statewide transmission plan. A Phase 2A final report was released in September 2009; the Phase 2B final draft report was released on May 20, 2010. Phase 3 will develop transmission plans for identified CREZs.[9] No firm date for release of the Phase 3 report has been publicly announced.

2. Western Renewable Energy Zones Initiative

The Western Governors' Association and the U.S. Department of Energy launched the Western Renewable Energy Zones (WREZ) initiative in May 2008. The WREZ initiative seeks to identify areas in the West with renewable resources to expedite the development and delivery of renewable energy to where it is needed. Renewable energy resources are being analyzed throughout the Western Interconnection. Stakeholders representing a variety of interests from throughout the region are participating in this collaborative process to produce reliable information to support the cost-effective and environmentally sensitive development of renewable energy in specified zones. The WREZ project will also produce conceptual transmission plans for delivering that energy to where it is needed within the Western Interconnection. The WREZ process is structured into four phases:

- Phase 1: Identify renewable energy zones (REZs).
- Phase 2: Develop a conceptual transmission plan to move power from REZs.
- Phase 3: Coordinate procurement to support commercial transmission projects and a regional market for renewable resources.
- Phase 4: Build interstate cooperation to facilitate transmission approvals, allocated costs, and ensure cost recovery.

The WREZ Phase 1 report was released on June 15, 2009, and represents the first step at identifying areas in the Western Interconnection that have both the potential for large scale development of renewable resources and low environmental impacts.

The WREZ initiative has also released a preliminary version of its WREZ Transmission Model. The Model is being developed to enable utilities, regulators, and others to evaluate the delivered price of power coming from specific REZs. The WREZ Peer Analysis tool is also being developed to allow a user, from the perspective of any individual load center, to create a supply curve associated with the entire list of renewable resources from all REZs in the Western Interconnection.[10]

F. Scoping Plan Measures

Two overarching strategies for obtaining GHG reductions from the electricity sector are demand-side strategies that reduce energy use, and supply-side strategies that lower GHG emissions associated with electricity generation. One of the key measures identified in the Scoping Plan to reduce GHG emissions from the electricity sector is the achievement of a 33 percent renewable portfolio standard by 2020. A summary of the electricity sector-related measures in the Scoping Plan is presented in Table IV-2.

Table IV-2
Recommended Electricity Sector-Related GHG Reduction Measures Identified in the Scoping Plan

Measure	Emission Reductions Counted Toward 2020 Target ($MMTCO_2e$)
Renewables Portfolio Standard (33% by 2020) (now referred to as the proposed RES)	21.3[g]
Energy Efficiency (32,000 GWh of Reduced Demand) • Increased Utility Energy Efficiency Programs • More Stringent Building & Appliance Standards • Additional Efficiency and Conservation Programs	15.2
Increasing Combined Heat and Power Generation by 30,000 GWh[h]	6.7
Million Solar Roofs (including California Solar Initiative, New Solar Homes Partnership and solar programs of POUs) • Target of 3000 MW Total Installation by 2020	2.1
Cap-and-Trade Program (Transportation, Electricity, Commercial and Residential, and Industry Sectors)	147[i]

Electricity Sector Specific Strategies

In addition to the RES, other electricity-related GHG reduction measures identified in the Scoping Plan include energy efficiency, combined heat and power, and the Million Solar Roofs Program.

The energy efficiency measures would set new targets for statewide annual energy demand reductions of 32,000 gigawatt-hours (GWh) and 800 million therms, from business as usual, between 2009 and 2020 and beyond. The targets represent a more aggressive goal than existing energy efficiency targets established by the CPUC for the IOUs due to the inclusion of strategies beyond traditional utility efficiency programs.

---

[g] In the Scoping Plan, the GHG emission benefits associated with 33 percent RPS are about 21.3 $MMTCO_2e$, increasing the renewable generation level from 12 percent to 33 percent. This represents about one $MMTCO_2e$ GHG emission benefits per one percent renewable generation increment. As a result, the GHG benefits are about 13 $MMTCO_2e$ for a 13 percent increment, from 20 percent to 33 percent renewable generation. These estimates are consistent with the GHG benefits for the proposed RES, high load forecast.

[h] Accounting for avoided transmission line losses of seven percent, this amount of CHP would actually displace 32,000 GWh from the grid.

[i] Represents the combined reduction from all the sectors listed from the 2020 Projected Business-as-Usual emissions level.

Key strategies include "Zero Net Energy" buildings that generate as much electricity as they consume through efficiency technologies and on-site power generation; more stringent building codes and appliance efficiency standards; voluntary and mandatory whole-building retrofits for existing buildings; more comprehensive utility programs to implement cost-effective efficiency measures; and providing real time energy information technologies to help consumers conserve and optimize energy performance.

Combined heat and power (CHP) produces electricity and useful thermal energy in an integrated system. The widespread development of efficient CHP systems would help displace the need to develop new, or expand existing, power plants. This measure sets a target of an additional 4,000 MW of installed CHP capacity by 2020 (compared to over 9,000 MW now in place), enough to displace approximately 30,000 GWh of demand through onsite generation.

As part of the Million Solar Roofs Program, the State has set a goal to install 3,000 MW of new solar capacity by 2017. Created under Senate Bill 1 (Murray, Chapter 132, Statutes of 2006), the Million Solar Roofs Program includes the California Solar Initiative (CSI) and the New Solar Homes Partnership. CSI is overseen by the CPUC and provides incentives for solar energy systems (from one kilowatt up to one MW) to residential, commercial, government, and non-profit customers in the IOU territories of Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E). The New Solar Homes Partnership provides financial incentives and other support for installing eligible solar energy systems on *new* residential buildings that receive electricity from PG&E, SCE, SDG&E, and Bear Valley Electric Service. Existing homes in PG&E, SCE, and SDG&E's areas are funded under the CSI incentive. The CEC implements the New Solar Homes Partnership in coordination with the CPUC as part of the overall CSI. The POUs are required, under Senate Bill 1, to adopt, implement, and finance solar incentive programs to place solar energy systems on residential and commercial properties. The POUs report on the progress of their solar incentive programs to the CEC on a yearly basis.

Additional Strategies

Another measure in the Scoping Plan that would impact GHG emissions from electrical generation is a California cap-and-trade program.

The cap-and-trade program is currently under development. It is currently designed to link with other regional partner jurisdictions in the Western Climate Initiative (WCI) to create a regional market system, and is one of the key measures that California plans to use to reduce the State's impact on climate change. Conceptually, the cap-and-trade program would establish a cap covering a large portion of the State's GHG emissions and allow trading to ensure cost-effective emission reductions. ARB staff is currently working on the cap-and-trade regulation to set up the framework and requirements for participation in the program. ARB staff released a preliminary draft regulation (PDR) for a California cap-and-trade program for public review on November 24, 2009. Under the

PDR, the cap is set for each compliance period, the first of which would begin on January 1, 2012. Under the staggered approach that was outlined in the Scoping Plan, entities in the electricity generation sector (including imports) would start in the first compliance period (2012).[11]

G. Renewable Energy Incentive Programs

Most states have incentive programs aimed at offsetting energy costs while promoting renewable energy technologies and energy efficiency. The U.S. Department of Energy has established a comprehensive database of federal, state, local, and utility policies and incentives that promote renewable energy and energy efficiency. This database is called the Database of State Incentives for Renewables & Efficiency (DSIRE) and is available via the Internet. DSIRE organizes financial incentives into the following categories: bond programs, corporate tax incentives, grant programs, green building incentives, industry recruitment/support, leasing programs, loan programs, Property-Assessed Clean Energy (PACE) financing, personal tax incentives, production incentives, property tax incentives, rebate programs, sales tax incentives, and utility rate discounts. Table IV-3 summarizes data available through DSIRE and provides a snapshot of the federal, state, utility, local, and private financial incentives related to renewable energy that are available in each of these categories. Examples of financial incentives available under these programs include a property tax exemption for the increase in property value due to the installation of a solar or wind-powered energy device; funding for manufacturers of renewable or clean-energy products to develop technologies or expand production; personal income tax credit for solar-electric equipment used on residential property; and low-interest loans for projects that save energy, produce energy from renewable resources, and use alternative fuels.

The DSIRE website (http://www.dsireusa.org/) contains an interactive U.S. map with summary information for each program in each state and associated hyperlinks to program websites where more detailed information can be accessed.

Table IV-3
States with Financial Incentive Programs for Renewable Energy

Source: Database of State Incentives for Renewables & Efficiency (DSIRE)
Federal = F, state = S, utility = U, local = L, private = P
The number indicates how many programs are available for that category.

State	Personal Tax	Corp. Tax	Sales Tax	Prop. Tax	Rebates	Grants	Loans	Industry Support	Bonds	Production Incentive
Fed.	F-3	F-4				F-3	F-5	F-1		F-1
AL	S-1				U-2	S-1	S-1, U-1			U-1
AK						S-1	S-2			U-1
AZ	S-3	S-1	S-1	S-2	U-6		U-1	S-1		
AR					S-1, U-1		U-1			
CA				S-1	S-6, U-38, L-2		S-2, U-1 L-3	S-1		S-1, U-2
CO			S-2, U-1	S-2	S-2, U-10, L-1	S-1, L-1	S-1, U-3, L-1			
CT			S-2	S-1	S-3, U-2	S-2	S-2, P-1	S-2		
DE					S-1	S-2				
FL		S-2	S-2		S-1, U-10, L-1		S-1, U-5	L-1		U-2
GA	S-1	S-1	S-1		S-1, U-9		U-1			U-2
HI	S-1	S-1		L-1	S-1, U-1		S-2, U-2, L-1	S-1		S-1
ID	S-1		S-1	S-1	S-1	P-1	S-1		S-1	P-1
IL			S-1	S-2	S-1, U-3	S-1, U-1, P-1	S-1		S-1	P-1
IN	S-1			S-1	S-1, U-4	S-1	U-1			U-1
IA	S-1	S-2	S-1	S-3	U-11	S-1	S-2, U-1			
KS				S-1	U-2		S-1	S-1		
KY	S-1	S-2	S-1		S-1, U-7	S-1	S-1, L-1, P-1			U-1
LA	S-1	S-1		S-1	S-1		S-2			
ME			S-1		S-2	S-1	S-1, P-1			S-1
MD	S-3	S-3	S-2	S-4, L-7	S-4, U-1	S-1	S-3	S-1		S-1
MA	S-1	S-2	S-1	S-1	S-3, U-5	S-4	S-1, U-1, P-1	S-3		S-1, P-1
MI				S-2	S-2, U-3	S-2		S-4		U-1
MN			S-2	S-1	S-4, U-22	S-2, U-2	S-6, U-2			S-1, U-1
MS					S-1, U-4		S-1. U-2			U-1
MO		S-1			S-1, U-9		S-1, U-4			
MT	S-3	S-1		S-3	U-4	U-1	S-1	S-2		P-1
NE			S-1		U-2		S-1			
NV			S-1	S-3	S-1, U-1		S-1			
NH				S-1	S-2, U-4		S-3, P-1			
NJ			S-1	S-1	S-6	S-1	S-1, U-1	S-1		S-2
NM	S-5	S-4	S-4	S-1			S-1	S-1	S-1	U-3
NY	S-3	S-1	S-1	S-2, L-1	S-6, U-3	S-2	S-3, L-1	S-2		
NC	S-1	S-1	S-1	S-2	U-5	S-1	S-3, U-1			U-3, P-1
ND	S-1	S-1		S-2	U-1		U-2			
OH		S-1	S-1	L-1	U-5, P-1	S-6	S-2, U-1, L-1	S-1		
OK		S-1			U-3		S-4, U-2	S-1		
OR	S-1	S-1		S-1	S-8, U-21	S-2, P-1	S-3, U-9	S-1		S-1, U-1, P-1
PA				S-1	S-1, U-1, L-1	S-8, U-1, L-2	S-6, U-1, L-5	S-3		S-1
RI	S-1	S-1	S-1	S-2	U-1	S-1	S-1, P-1			P-1
SC	S-1	S-2	S-1		S-1, U-5		S-1, U-5			S-1, U-2, P-1
SD			S-1	S-4	U-5		U-2			
TN				S-1	U-1	S-2	S-2, U-1	S-1		U-1
TX		1		S-1	U-21, L-2	S-2	S-2	S-1		U-2

State	Personal Tax	Corp. Tax	Sales Tax	Prop. Tax	Rebates	Grants	Loans	Industry Support	Bonds	Production Incentive
UT	S-1	S-1	S-1		S-1, U-6			S-1		
VT	S-1	S-1	S-1	S-1	S-1	S-2, U-1	S-2, P-1			S-1, U-2
VA				S-1			S-1	S-2		U-1
WA			S-1		U-16	L-1, P-1	U-13	S-1		S-1, U-3, P-1
WV	S-1	S-1		S-1						
WI			S-1	S-1	S-7, U-4	S-1, U-2	S-2, U-1, L-1	S-2		U-5
WY			S-1		S-1, U-1		U-2			

REFERENCES

[1] California Public Utilities Commission (Division of Strategic Planning), 2006. Renewable Energy Certificates and the California Renewables Portfolio Standard Program (Staff White Paper), http://docs.cpuc.ca.gov/published/Report/55606.htm

[2] California Energy Commission, 2008. *Overall Program Guidebook*, Second Edition, http://www.energy.ca.gov/2007publications/CEC-300-2007-003/CEC-300-2007-003-ED2-CMF.PDF

[3] California Public Utilities Commission. California Renewables Portfolio Standard (RPS), http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm

[4] California Public Utilities Commission, 2001. *Order initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program,* http://docs.cpuc.ca.gov/published/Final_decision/27360.htm

[5] U.S. Department of Energy, 2010. *Database of State Incentives for Renewables & Efficiency (DSIRE)*, http://www.dsireusa.org/

[6] California Public Utilities Commission (Prepared by Energy and Environmental Economics, Inc.), 2007. CPUC GHG Modeling Stage 1 Documentation (Attachment B), http://docs.cpuc.ca.gov/efile/RULINGS/75043.pdf

[7] California Public Utilities Commission, 2009. *33% Renewables Portfolio Standard Implementation Analysis Preliminary* Results, http://www.cpuc.ca.gov/NR/rdonlyres/B123F7A9-17BD-461E-AC34-973B906CAE8E/0/ExecutiveSummary33percentRPSImplementationAnalysis.pdf

[8] Renewable Energy Transmission Initiative, 2008. *California Renewable Energy Transmission Initiative Mission Statement,* http://www.energy.ca.gov/reti/Mission_Statement.pdf

[9] Renewable Energy Transmission Initiative, 2010. *Renewable Energy Transmission Initiative (RETI) Frequently Asked Questions (FAQ),* http://www.energy.ca.gov/reti/RETI_FAQ.PDF

[10] Western Governors' Association and U.S. Department of Energy, 2009. *Western Renewable Energy Zones – Phase 1 Report,* http://www.westgov.org/wga/publicat/WREZ09.pdf

[11] ARB, 2008. *Climate Change Scoping Plan*, (Pages 30-38, 41-46, 53-55), http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf

V. TECHNOLOGY ASSESSMENT

In order to meet a 33 percent renewable target, California's retail sellers will have to procure more electricity from renewable resources. In general, the resources used to meet the 20 percent requirement in the RPS program will also be used to meet a 33 percent renewables target. Integrating new renewable energy with California's grid will be challenging, especially in terms of building adequate new transmission and maintaining and balancing grid operations.

This chapter discusses different types of renewable resources that are eligible for CEC certification under the RPS and RES programs. It also presents the existing and planned procurement of renewable generation that California's retail sellers expect to use to meet RPS requirements. In addition, this chapter will discuss potential renewable generation development for achieving a 33 percent renewable energy target and the infrastructure improvements necessary to integrate additional renewable electricity into the California grid.

A. Description of Renewable Resources

The following section provides a brief description of renewable resources or technologies eligible for CEC certification under the RPS program.[a] As discussed later in this chapter, the resources expected to make up the majority of the renewable generation in 2020 are geothermal, solar, and wind generation. Today, wind and geothermal generation represent about 75 percent of the generation from renewable resources, or about 22,000 GWh, and solar generation represents less than one percent of renewable generation. By 2020, wind, solar, and geothermal generation is expected to represent 85 percent of the renewable generation, or about 64,000 GWh—a three fold increase.

1. Wind Generation

Wind generation is a well developed technology in California. Overall, by the end of 2008, California had about 2,500 MW of wind generation capacity.[1] Large turbines are used to harvest the blowing winds to generate electricity. Utility scale wind generation plants typically include hundreds of wind turbines. These wind generation plants are located mainly at Altamont Pass, the Tehachapi Mountains, and San Gorgonio Pass.[2] Wind resources have variable operation due to diurnal and seasonal fluctuations in wind patterns.

The first turbines were installed in California in the early 1980's. These early turbines had a capacity rating of 25 to 250 kw each. Today, the turbines are much larger, typically having a generating capacity greater than one MW—the largest turbines have generating capacities exceeding 7 MW. Additionally, the newer wind turbines are more efficient in that they can generate electricity at

[a] See California Energy Commission Report: Renewables Portfolio Standard Eligibility, Third Edition, for the requirements that must be satisfied by renewable resources to be RPS eligible.

much slower wind speeds. This higher efficiency results in better performance which is demonstrated by a higher capacity factor for the turbines. For example, the wind turbines at Altamont Pass are older model turbines that typically operate at a 15 percent capacity factor.[3] The newer wind turbines located at the Tehachapi Mountains typically operate at a 30-40 percent capacity factor.[4]

2. Solar Generation

The types of commercial solar plants include solar thermal, solar dish-engine, and solar photovoltaic (PV). Solar plants convert the energy from solar radiation into electricity by using a turbine or heat engine or, in the case of PV, by using panels that generate electricity directly. Today, there are seven solar thermal projects with a combined capacity of 360 MW and three PV solar projects with a capacity of 35 MW operating in California. The CEC currently has nearly 5,000 MW of solar projects proposed in its power plant siting process.[5] Solar power plants have a capacity factor range of 18-25 percent[6,7] without energy storage. As with wind, solar resources operate variably due to diurnal, daily and seasonal fluctuations in available sunlight. However, solar generation is more predictable than wind power, and has the added advantage in that solar intensity peaks during the summer when California faces its highest air conditioning and overall demand for electricity.

a. Solar Thermal

There are two types of commercial solar thermal electricity generating units: central tower, or Heliostat, and parabolic solar trough. Both types of solar thermal plants can have a fluid reservoir that can store enough heated fluid to operate the turbine for several hours. In addition, the plants often have natural gas-fired auxiliary heaters and boilers to help with starting the plant and to keep the plant operating at night and on cloudy days.[b]

Central tower operations use an array of mirrors that track the sun's movement and focus the sunrays on a collection tower. The tower holds a thermal boiler that absorbs the solar radiation and heats a working fluid to a temperature high enough to super heat water. The working fluid is then run through a heat exchanger where water is super heated into steam. The steam is injected into a turbine to generate power. There are approximately 550 MW of proposed central tower generation projects in the power plant siting process at the CEC.[5]

The parabolic solar trough uses a parabolic shaped mirror to concentrate the solar radiation on a fluid-filled tube that is positioned in the focal point of the trough. The solar energy heats the fluid, which is then pumped into a heat exchanger where water is heated to steam. The steam is injected into a turbine to generate electricity. There are approximately 2,700 MW of proposed parabolic trough generation projects in the siting process at the CEC.[5]

[b] This portion of the plant's generation would not count as renewable under the proposed RES.

b. Solar Dish-Engine

The solar dish-engine converts heat energy into mechanical motion that is used to generate electricity. The system uses mirrors arranged in a dish shape to concentrate the solar energy to a focal point where the engine is positioned. The thermal energy heats the working fluid, which expands in a high temperature cylinder and turns a crankshaft that is connected to an electricity generator. The working fluid is then cooled in a low temperature cylinder and pumped back into a receiver where it is heated and then injected into the high temperature cylinder to complete the cycle. There are approximately 1,600 MW of proposed solar dish-engine generation projects in the siting process at the CEC.[5]

c. Photovoltaic Solar

Photovoltaic solar systems convert solar radiation directly into electrical energy by using a solid-state electronic process. The two common types of PV cells are crystalline silicon based and thin film. Currently, crystalline silicon PV cells dominate the PV market. However, the cost to produce thin film PV cells is dropping significantly and thin film is expected to be the primary choice for PV cells in the future. There are approximately 36 MW of utility scale solar PV in operation.[8] In addition, the large IOUs have signed contracts to bring 2,500 MW online to meet RPS requirements. Most of the PV in use today is located on residential and commercial roofs. In this application, the energy from the PV lowers the overall electricity load.

3. Geothermal Generation

Currently, geothermal power facilities generate 1,800 MW in California.[9] These geothermal power plants are primarily located in Imperial, Inyo, Sonoma, and Lake Counties. These resources are desirable energy production sources in that they operate at a high capacity factor—typically 90 percent or higher. Consequently, CAISO and other balancing authorities use these units in baseload applications. The capacity of these geothermal resources has been declining somewhat because of plant retirements and for some facilities, a reduction in steam flow. As discussed later in this chapter, substantial additional geothermal generation will be added to the portfolios of several POUs as part of their effort to comply with the RPS targets.

The three types of commercial geothermal power plants are dry steam, flash steam, and binary. In a dry steam unit, steam used to drive a turbine is produced by the geothermal reservoir and is injected directly into the turbine. The steam is either vented to the atmosphere or condensed and injected back into the earth. The geology that supports dry steam units is found only in a few locations around the world. In California, dry steam power plants have been built at the Geysers located in Lake County.

Flash steam systems are found in geothermal areas that have a lower temperature than dry steam areas, resulting in a mixture of water and steam coming from the production well. The mixture is fed into a low-pressure tank where the steam is separated from the water and injected into the turbine. The remaining water is either flashed in a secondary tank or injected into the geothermal aquifer to replenish it. As with dry stream power plants, the steam is either vented to the atmosphere or condensed and injected back into the earth. In California, flash steam power plants have been built near the Salton Sea located in Imperial County.

A binary system uses a low boiling point intermediate fluid to drive the turbine. This system is used at sites where low temperature feed water is available that can provide the energy needed to operate a steam turbine. The moderately heated water that comes from the production well is run through a heat exchanger where it heats the intermediate fluid. The two fluids are kept in separate operating loops that do not mix. The geothermal water is then cooled in a condenser and injected back into the geothermal aquifer. In California, binary power plants have been built at Casa Diablo located near Mammoth and Honey Lake located in Lassen County.

4. Biomass Combustion

As of 2006, there were about thirty biomass combustion plants proving 640 MW[10] located throughout the state that use either agricultural waste, forest waste, or construction waste as fuel to generate electricity. Similar to geothermal plants, biomass combustion plants can operate at a high capacity factor—typically exceeding 90 percent. Hence, these plants are also part of the generating resources used to provide baseload generation.

Biomass combustion plants typically use natural gas to start the boiler and as necessary to ensure proper operation. During the start-up process, natural gas is used to warm up the system. When the proper temperatures are reached, the biomass is then fed into the boiler. Agricultural waste includes green wastes from farming activities such as prunings, orchard removals, and field waste. Some of the plants located in the northern part of the State rely heavily on forest waste. Construction waste includes wood waste that is diverted from a landfill. Many of these plants are located within the Sacramento and San Joaquin Valleys.

There are two types of plants: wood-fired boiler and fluidized bed combustors. Wood fired boilers burn wood on a grate in a controlled manner to transfer heat to the boiler section. The heat from the boiler is used to generate steam for the steam turbine. The steam turbine converts the steam into electricity. Fluidized beds suspend solid fuels on upward-blowing jets of air during the combustion process. The result is a turbulent mixing of gas and solids, which provides more effective mixing and heat transfer.[11] The resulting steam produced by the fluidized bed combustor is sent to a steam turbine to generate electricity.

5. Landfill and Digester Gas Combustion

Landfill gas is a combination of methane, other trace hydrocarbons and CO_2 plus some impurities such as hydrogen sulfide that results from the anaerobic breakdown of the waste placed in landfills. The amount of methane and CO_2 emitted will depend upon a number of factors, including the types of waste in the landfill, the structure of the landfill, and the moisture available (typically provided by rainfall). Landfill gas emissions are reduced if there is little biological waste interned at the landfill or if the landfill is located within an arid area. Since landfill gas emissions are based on anaerobic breakdown of a portion of the waste, the gas emissions will cease once there is no longer material in the landfill that would be affected by the anaerobic process. There are 367 landfills in California that take biogenic waste. About 132 of these landfills are equipped with landfill gas collection systems and control devices. These 132 landfills produce about 95 percent of the landfill gas emissions in the State.[12] In some cases, the gas flow is large enough to make installation of an energy recovery system, such as an engine or combustion turbine, economically attractive to generate electricity.

Digester gas is a combination of methane, other trace hydrocarbons and CO_2 plus some impurities, resulting from the anaerobic breakdown of biogenic waste at waste water plants, dairies, and other facilities. The digesters need heat to operate properly. The digester gas can be used in a boiler to provide heat to a digester, or alternatively, an engine, fuel cell, or turbine can be used to provide both heat to the digester and generate electricity.

6. Biomass Conversion to Renewable Diesel

Another renewable resource involves converting biomass to renewable diesel and then generating electricity by combusting the renewable diesel in an engine generator. There are currently no facilities that use biomass as feedstock to create renewable diesel. One technique to convert biomass into renewable diesel is the Fischer-Tropsch (F-T) process to produce diesel.[13] The F-T process is energy intensive, but in addition to producing renewable diesel, electricity and naphtha are produced as co-benefits. Due to the higher value of renewable diesel as a transportation fuel to satisfy California's low carbon fuel standard, staff believes that it is unlikely that a new plant would be constructed in California to convert biomass to renewable diesel for electricity production.

7. Biogas Injection

Biogas injection refers to the injection of a renewable biogas, such as landfill or digester gas, into a natural gas pipe line. Biogas is typically composed of methane, CO_2, and other contaminants. Prior to injection into the pipe line, the biogas must be processed to satisfy pipeline purity requirements, which requires the removal of the CO_2 and other contaminants.[14] The resulting biogas, typically

referred to as biomethane because of its similarities to methane, is added to the natural gas pipeline to be combusted in a natural gas power plant.

Three facilities in California are combusting a mixture of biomethane/methane in natural gas power plants to generate electricity. For these applications, the amount of biogas injected is a fraction of the total gas being delivered to the power plants.

8. Municipal Solid Waste

In recent years, there have been significant efforts to reduce the amount of municipal solid waste (MSW) being placed into landfills. After implementation of waste diversion programs, additional options were considered to further reduce the amount of waste going to landfills, including direct combustion or the conversion of the MSW into a fuel. Each of these options is discussed below.

Direct combustion refers to feeding MSW, after waste segregation, directly into a mass-burn boiler, to generate electricity. There are three existing direct combustion facilities in California with a total capacity of 60 MW. Each of the facilities is equipped with air pollution control equipment that minimizes air emissions.

MSW conversion refers to two thermochemical conversion processes: gasification and pyrolysis. Gasification creates gaseous fuels that can be condensed into liquid fuels or directly combusted in an engine or turbine for electricity generation. Pyrolysis can create liquid and/or gaseous fuels that can also be used to generate electricity.

The gasification process converts MSW to a fuel without oxygen or in an oxygen deficient environment, with temperatures above 1,300 degrees Fahrenheit. The process is designed to create mostly fuel gases, also called syngas, that include carbon monoxide, hydrogen, and methane. The high temperatures minimize the creation of liquid and solid chemical products such as water, char, and ash. As of 2008, Asia and Europe have commercial facilities in operation; North America does not.

Pyrolysis is a conversion process that can be completed without the addition of air or oxygen. Pressure and temperature are used to control the reaction to maximize the conversion of solid, liquid, and gaseous products. The temperatures for the reactions are typically 750 -1,650 degrees Fahrenheit. The process is similar to gasification with more control over the process to prevent liquid products from vaporizing and becoming gaseous. Currently, there are commercial pyrolysis facilities operating in Europe and Asia. California has one operational research facility. Neither the direct combustion nor conversion of MSW is currently considered a renewable energy source under existing requirements.

9. Hydropower

Hydroelectric generation takes advantage of the energy from moving water to power turbine generators. Hydroelectric generation is generally considered renewable generation. Only small hydroelectric operations with generating capacity of 30 MW or less are currently considered RPS-eligible facilities in California.[c]

10. Ocean Technologies

Ocean technologies refer to the following types of renewable generation: ocean wave, ocean thermal, and tidal current.[15] Ocean wave refers to technologies that take advantage of the energy contained in the waves on the ocean surface. Ocean thermal include technologies that can take advantage of the differences in the temperature of the ocean at different depths. Tidal current technologies use energy contained in the changing tides. Typically, dam-like devices are used to capture the incoming tide and the collected water is released via generators, the same way a dam operates, to generate electricity. At this time, staff is not aware of commercial products that can be used to harness the energy contained in the oceans near California.

11. Storage Technologies

While storage is not a renewable resource itself, the use of utility-scale energy storage in conjunction with variable renewable resources will allow for easier integration of these technologies onto the grid. The benefits of energy storage technologies include the ability to utilize over-generation capacity (i.e., there is more available renewable generation than needed to meet grid demand and generators must either decrease production or provide electricity either at no cost or loss), supply energy quickly, shift energy from off-peak to on-peak delivery, and provide voltage support.[16]

Battery storage and pump-hydro are the primary storage systems in use today. Most of the other types of energy storage technologies are still in the development stage. Battery storage and pump-hydro storage systems have been used for many years. The current battery storage technology is relatively expensive and the storage capacity is limited in that power can only be delivered at the rated output for 10 to15 minutes. Additional developmental work is needed to advance the battery technology to allow more widespread use of this technology in utility applications. Pump storage uses less expensive electricity at night to move water to a reservoir behind a hydroelectric dam. The stored water can then be used later to generate electricity when there is greater demand. This

[c] Incremental increases in generation that results from efficiency improvements to a hydroelectric facility, regardless of electrical output of the facility, can be eligible for the RPS if it satisfies certain conditions. See CEC report: Renewables Portfolio Standard Eligibility, Third Edition for specific requirements.

operation is an example of shifting energy from off-peak to on-peak delivery. There are currently two large pump storage facilities in the State. Future development of new pump storage facilities is not expected due to its high expense and limited locations where this type of facility can be constructed.

Other storage devices under development include the following:

- Battery storage technologies including sodium-sulfur batteries, lithium-ion batteries, and flow batteries which use large tanks of a rechargeable electrolyte to store energy. Three types of electrolytes have been developed thus far: zinc-bromide, vanadium redox that uses sulfuric acid, and sodium-bromide;
- Flywheel technology where energy is stored in a flywheel by accelerating a flywheel to a very high speed and storing energy as rotational energy;
- Hydrogen storage, where the stored hydrogen can be used to produce electricity in a fuel cell or used as fuel in a boiler or engine;
- Compressed air storage, where air can be stored in a reservoir and a wind turbine is used to both compress the air and to recover the energy;
- Super capacitors, which are able to store great amounts of energy; and
- Plug-in hybrids, where batteries of electric cars are used to store electricity during off-peak periods and the excess energy from the plug-in hybrid can be used to load balance or be added back to the grid during peak electricity demand.

B. Renewable Generation Development

This section presents a summary of renewable generation in California for 2008 and the planned procurement by California retail sellers of electricity to meet their RPS obligations.

1. Current Generation

In 2008, renewable energy, excluding large hydropower, accounted for approximately 11 percent of California's total electrical generation, as shown in Table V-1. In-state generation provides about 90 percent of the total generation from renewable sources. The other ten percent is from out-of-state generation.

Table V-1
2008 Renewable Energy Generation[d]
(GWh)

Resource	In-State	Out-of-State	Total Generation
Biomass	5,700	700	6,400
Geothermal	13,000	800	13,800
Small Hydro	3,700	700	4,400
Solar	700	20	720
Wind	5,700	1,600	7,300
Total	28,800	3,820	32,620

Source: CEC Energy Almanac[17]

2. Expected Renewable Generation under the RPS Program

Under the RPS program, retail sellers of electricity that are regulated by the CPUC (IOUs, ESP, CCAs) are required to meet the 20 percent renewables target by the end of 2010. Note that retail sellers are allowed three years to make up any shortfalls in any year, essentially giving them until the end of 2013 to meet the 20 percent target. POUs can set their own renewable targets and compliance dates to satisfy RPS obligations. Consequently, the POU procurement rates for renewables are expected to be different than the retail sellers regulated by the CPUC subject to the 20 percent requirement.

Renewable generation can be from either resources owned by the retail seller or from a generator which is under contract to deliver the generation to the retail seller. The remainder of this section includes a discussion of the expected renewable generation portfolio for each type of retail seller in California based on data submitted to CEC or CPUC under the RPS program.

a. Large IOU Renewable Portfolios

The three largest IOUs subject to the 20 percent RPS requirements provide about 70 percent of the State's electric retail sales. According to the CPUC, these three IOUs collectively served 15 percent of their 2009 retail electricity sales with renewable power. Pursuant to the requirements of the RPS, the large IOUs are required to develop renewable energy procurement plans and hold annual solicitations for renewable energy to reach and maintain the 20 percent RPS requirement. Since 2003, the IOUs have signed over 180 contracts for about 19,000 MW of renewable generation capacity.

Additionally, prior to the RPS, each IOU received energy from renewable generation via long term contracts, principally from geothermal and biomass combustion generation.[18,19,20] Many of these long-term contracts are set to

[d] The total electricity demand in California in 2008 was nearly 286,000 GWh.

expire by the end of 2020. From 2013 to 2020, all three IOUs collectively will have nearly 10,000 GWh of renewable generation from contracts scheduled to expire. At this time, it is unclear if the generation represented by the contracts will be extended at the expiration date or replaced by other renewable generation.

Table V-2 summarizes the projected generation procured by the large IOUs for 2010 and 2018. To be consistent with the POU information discussed in the next section, 2018 was chosen as the future year reference. The projected generation for both years includes the generation procured for the RPS and the renewable generation procured by IOUs prior to the RPS program. For the 2010 projection, the RPS contracts that are included are operational projects. The 2018 projection includes the delayed, on-schedule, and pending approval contracts identified in CPUC's RPS Status Table, updated March 30, 2010.[21]

Table V-2
Summary of RPS Renewable Generation Contracted to IOUs

	2010 Projected		2018 Projected	
Resource	**Energy Production (GWh)**	**Percent of Renewable Production**	**Energy Production (GWh)**	**Percent of Renewable Production**
Biogas	1,000	3	800	1
Biomass	4,000	12	3,800	6
Conduit and Small Hydroelectric	3,900	12	3,300	5
Geothermal	15,000	45	17,000	25
Solar	700	2	22,000	32
Wind	8,700	26	20,000	30
Total	33,300		66,900	

The RPS contracts were negotiated by each IOU and generator to satisfy the annual RPS procurement requirements. As such, the contracts can vary in length from less than one year to 30 years. Many of the short-term contracts were intended to satisfy IOU's near-term RPS deficits associated with the 20 percent target. In some cases, the same generation may be included in the CPUC's contract database as several short-term contracts.

The RPS contracts represent a range of generation readiness. Some projects are online and can provide renewable generation once the contract has been approved, other projects are several years away due to the time needed to obtain the necessary approvals for permits, financing, and the need for new transmission infrastructure. Some of these projects may never be built. To date, seven percent of the approved contracts have been terminated[22] and a number of other projects have fallen behind their projected schedule. As of the second

quarter 2010, 71 of the 180 signed contracts represent operating generation. The other 109 contracts have been either approved by CPUC or are pending CPUC approval. Most of the facilities are not yet on-line.

The majority of the IOU's renewable generation today is from geothermal and wind generation. About 45 percent is from geothermal generation and another 26 percent is from wind. If all of the approved contracts are fulfilled, the amount of renewable generation will double. Today, solar generation represents a small portion of operating renewable generation under contract. If all the contracts are fulfilled, wind and solar would represent over 60 percent of the total renewable generation, or put another way, the total generation from wind and solar will be four times greater than the wind and solar generation that is currently available.

b. POU Future Renewable Portfolios

Staff used CEC's 2009 report, *An Assessment of Resource Adequacy and Resource Plans of Publicly Owned Utilities in California* (Report),[23] to estimate projected renewable portfolios for POUs. Because the summaries provided for LADWP and SMUD were not sufficiently detailed, information from the individual resource adequacy reports for LADWP and SMUD that were filed with CEC were used.[24] Staff also used information from an ARB survey of POUs that identified additional out-of-state facilities that are not included in the Report.

The Report contains the 2010 and 2018 projects from the 10-year resource plans filed by the largest 15 POUs, which show how forecast loads will be served by electricity supplies. One of the POUs listed in the report is the Northern California Power Agency (NCPA). NCPA has 14 smaller POU members who collectively purchase renewable generation and share the electrical output.[e]

Table V-3 summarizes the renewable energy portfolio for the 14 largest POUs (excluding "NCPA" data), which represents over 90 percent of total electricity sales by POUs. In 2010, these utilities are expected to deliver approximately 45,000 GWh of electricity to retail customers.

[e] Within NCPA, each of the NCPA resources is actually owned by different groupings of POU members. The renewable resources are attributed to the POU taking the share of the "NCPA" resource. Ten members of NCPA collectively report resource data to CEC under the entity "NCPA" and four members report individually. Because individual data for the 10 members was not available in the report, staff chose not to include resources reported under "NCPA" in this analysis.

Table V-3
POU Renewable Generation

Resource	2010 Projected		2018 Projected	
	Generation (GWh)	Percent of Total	Generation (GWh)	Percent of Total
Biogas	250	3	1,500	9
Biomass	700	9	300	2
Geothermal	1,200	15	5,500	34
Solar	40	<1	900	6
Wind	4,700	59	6,300	39
Unspecified	1,100	14	1,600	10
Total	7,890		16,100	

In 2010, the POUs are expected to have about 8,000 GWh of renewable energy. Most of this generation is based on long term contracts with renewable generators. Unlike IOUs, POUs are allowed to use "self-certified" resources for RPS compliance. Many of the POUs receive generation from large hydroelectric plants that have a capacity greater than 30 MW. The RPS program does not allow IOUs to use this type of resource as an eligible resource for RPS compliance, but does not preclude POUs from claiming larger hydro generation as part of their efforts to reach their voluntary renewable targets. The estimates given above exclude approximately 1,000 GWh of large hydroelectric, digester gas, and aqueduct hydropower generation, and RECs that were included in some POU's renewable portfolios (See Chapter VII for more complete discussion on uncertified POU resources). Nearly 60 percent of the POU renewable generation expected in 2010 will be from wind generation. Other major contributors to the current renewable portfolios include geothermal generation, representing 15 percent, and biomass generation, representing nine percent.

By 2018 (the future year used for resource planning purposes), renewable generation procured by POUs would double if all currently envisioned contracts are fulfilled. This would represent about 25 percent of the retail electricity sales by POUs. Wind would continue to be a large share of the renewable portfolio, representing nearly 40 percent of total renewable generation. In contrast to the renewable generation contracted for by the large IOU's, solar generation would represent only a small portion of POU's renewable portfolios in 2018, about five percent. Overall, wind and solar generation is expected to increase by 60 percent between 2010 and 2018. Additionally, geothermal and biogas generation would continue to be a large part of the POU's portfolio, representing another 35 percent (an increase of nearly four times 2010 levels) and 10 percent respectively. As compared to the geothermal and biogas generation under contract to the large IOUs, which represents about 26 percent of their portfolio. It should be noted that 10 to14 percent of the portfolio of renewable generation for 2010 and 2018 is identified as unspecified renewable energy. The specific resources will be determined at a later date.

c. Electric Service Providers (ESP) Portfolio

As of 2009, 13 percent of the 16,000 GWh of retail electricity sales by ESPs[f] serving California customers are from renewable resources. Table V-4 summarizes the renewable portfolio data submitted as part of the March 2010 fillings with the CPUC.[25] Most of the renewable electricity purchased by ESPs is from short-term contracts. Consequently, staff cannot make an assessment of future progress for ESPs. Additionally, since a customer can change to a different ESP or return to the IOU that is serving the customer's territory, the number of customers for ESPs can change from year-to-year. Consequently, the procurement requirements can also vary significantly from year-to-year. The information given in Table V-4 is a snap-shot and may not be representative of future years. For 2009, wind and geothermal generation represent nearly 90 percent of the renewable portfolio for ESPs.

Table V-4
Renewable Generation Contracted to ESPs

Resource	2009 Renewable Contract Generation (GWh)	Percent of Total
Biogas	70	3
Biomass	10	<1
Geothermal	500	25
Hydro	150	7
Wind	1,300	64
Total	2,030	

d. Multijurisdictional and Small IOU Portfolio

This group of retail sellers includes two small IOUs and two multi-jurisdictional utilities. These utilities collectively serve less than one percent of the electricity to California end users. Table V-5 summarizes the data for the two multi-jurisdictional IOUs, based on the March 2010 filings with the CPUC.[26]

[f] ESPs include entities such as Calpine Power and Shell Energy. Collectively, eight ESPs are now operating in California.

Table V-5
Renewable Generation Contracted to Multi-Jurisdictional IOUs

Resource	2009		2013 Projected	
	Generation (GWh)	Percent of Total	Generation (GWh)	Percent of Total
Biogas	0.2	<1	29	10
Geothermal	122	57	113	40
Small Hydro	42	20	51	18
Wind	49	23	92	32
	213		285	

Currently, these utilities have procured 13 percent of their generation from renewable sources. The renewable generation is a mixture of retail seller owned and long-term contracts. About 60 percent of the renewable generation is from geothermal sources. The remaining 40 percent is evenly split between small hydroelectric generation and wind generation. This group of retail sellers is collectively projected to procure 18 percent of their generation as renewable by 2013, the year affected retail sellers can make up shortfalls experienced in 2010. Geothermal and wind generation make the largest contribution to these retail sellers' future renewable portfolio, representing nearly 75 percent of the portfolio.

e. Out-of-State Renewable Generation

As discussed above, many of the retail sellers of electricity have procured some out-of-state renewable generation. To assess the amount of out-of-state renewable generation being delivered to California, ARB staff reviewed the large IOU contract database, the renewable generation owned or contractually obligated to the POUs,[21] and survey data from POUs regarding out-of-state renewable generation.[27] For the POUs, this assessment was limited to the 14 largest POUs. These 14 POUs account for 90 percent of the load served by POUs. Overall, this assessment included the renewable generation for retail sellers that collectively provide about 90 percent of the electricity needs for California. For this analysis, LADWP provided updated information on three new wind projects that began generating this year and were not included in the 2009 CEC report: *An Assessment of Resource Adequacy and Resource Plans of Publicly Owned Utilities in California.*

Table V-6 indicates the amounts of renewable generation, by category, that are expected to be delivered to California by 2010 and 2018. As shown in Table V-6, substantial out-of-state generation has been procured for biogas, small hydroelectric, solar, and wind generation. Additionally, about three-quarters of the wind generation is coming from out-of-state in 2010. The out-of-state share decreases to about 50 percent by 2018. Significant increases in solar generation are expected from 2010 to 2018, but the percent from out-of-state will stay the same. Overall, about two-thirds of the total generation for 2010 is expected from

in-state resources. By 2018, the share of in-state generation would increase to almost three-quarters if all existing and pending contracts result in projects coming on-line by that time.

Table V-6
In-State and Out-of-State
Renewable Generation for IOUs and POUs

	2010			2018		
Resource	**In-State Generation (GWh)**	**Out-Of State Generation (GWh)**	**In-State Percentage**	**In-State Generation (GWh)**	**Out-Of State Generation (GWh)**	**In-State Percentage**
Biogas	1,400	600	70	1,400	600	70
Biomass	4,300	300	93	3,700	300	93
Geothermal	14,600	500	97	20,000	1,000	95
Small Hydroelectric	3,900	500	89	3,200	500	86
Solar	680	20	97	17,000	5,400	76
Wind	5,000	7,900	39	13,000	12,000	52
Miscellaneous	2,000	0	100	4,800	300	94
Overall	31,880	9,820	66	55,270	20,100	73

C. Potential Renewable Resources to Satisfy the Proposed 33 Percent RES

This section describes the methodology that ARB staff used to estimate how renewable generation could be expanded by 2020 to meet the 33 percent renewable energy target in the proposed RES regulation. In this analysis, ARB staff calculated various renewable energy scenarios to illustrate a range of potential energy mixes that could provide a 33 percent renewable power supply to the California grid in 2020. The resulting scenarios serve as the basis for evaluating incremental differences between the current 20 percent RPS requirement and the proposed 33 percent RES regulation. This is conducted using the upper and lower boundaries of a load-demand forecast for 2020 to cover a range of potential renewable energy outcomes. The scenarios also serve to identify the potential regional locations of new renewable resources as well as the cost of building resources and delivering them to a reliable electricity grid in 2020. The information produced in this analysis is used in the environmental and economic analyses found in Chapter IX (Environmental Analysis) and Chapter X (Economic Analysis) of this report.

In 2009, Energy and Environmental Economics, Incorporated (E3) developed a 33 percent RPS Calculator (RPS Calculator)[28] to conduct a 33 percent

Implementation Analysis[29] for the CPUC in response to anticipated legislation for a 33 percent RPS. More recently, E3 modified that version of the RPS Calculator to reflect updates in costs and renewable resource characterizations and to incorporate new modules related to the proposed RES regulation on behalf of the ARB. The updated version of the calculator, now referred to as the "RES Calculator," is the result of those updates and modifications and is available for download on the RES website.[9] Like the original calculator, the RES Calculator uses a series of inputs related to the costs, locations, and availability of renewable resources found both inside and outside California, including transmission line requirements and environmental concerns. Listed below is an overview of how the RES Calculator selects renewable resources predicted to come on-line by 2020, differences between the RES Calculator and the RPS Calculator, and the results of a scenario analysis comparing a 20 Percent RPS and a 33 Percent RES scenario.

1. RES Calculator Methodology

The RES Calculator is an economic-based model developed to estimate the costs and feasibility of procuring conventional and renewable energy for California utility companies to meet a potential 33 percent renewable energy standard in 2020. The RES Calculator evaluates information from the California energy agencies, ARB, the Energy Information Administration, consultants, stakeholders, and the Renewable Energy Transmission Initiative (RETI), among other sources, to select a least-cost renewable resource mix that is compatible with existing and planned transmission goals. This task is conducted by selecting a mix of renewable resources based on current California utility contracting activity and the costs, environmental impacts, and energy output associated with developing resources and delivering them to one of two major load centers in California. The RES Calculator also provides the capability to specify a number of inputs such as a reduction of load demand due to changes in energy efficiency, the availability of out-of-state resources, and the costs of renewable resources, making it an effective tool for forecasting renewable resources that can be integrated into a reliable California electricity system in 2020.

a. Resource Selection Methodology

The RES Calculator selects groups of renewable resources based on commercial interest, cost, and environmental footprint from resource zones located in California and throughout the WECC. This method of grouping reliable renewable resources ensures the calculator gets full use of transmission line capabilities needed to deliver energy to either the San Francisco or Los Angeles region to serve electricity demand or load. The operation is conducted through two primary tasks. First, the RES Calculator evaluates renewable energy resource zones as groups of resources both within California and from

[9] The RES Calculator is available at http://www.arb.ca.gov/energy/res/res.htm

out-of-state regions that have excess renewable resources above those required to meet local or state RPS programs.

The RES Calculator then sorts resources based on the delivered cost of energy to California. This includes the cost of generating the electricity, transporting it across the transmission system, and integrating it into the California electricity grid. Included in the resource selection are: cost-ranking penalties for resources that are located in environmentally sensitive areas or subject to issues that could compromise their ability to obtain the necessary permits required to achieve full operation by 2020; and cost-ranking bonuses for resources with demonstrated commercial interest such as a contract to deliver energy to a California utility. Finally, the RES Calculator evaluates the average per-MWh cost of delivering energy to a California load center and selects groups of renewable resources in merit order until sufficient renewable energy is selected to meet a 33 percent target.

b. Weighting of Inputs and Environmental Scoring

The RES Calculator incorporates a renewable energy project ranking system based on information obtained from the RETI Phase 1B[30] analysis and a scoring mechanism developed by Aspen Environmental Group (Aspen) as part of the CPUC 33% Implementation Analysis.[31] While RETI identifies environmental concerns related to CREZs, the analysis does not include specific issues related to individual renewable energy projects. The Aspen scoring mechanism builds on information developed through the RETI process. This scoring mechanism examines individual projects and scores them based on the RETI identified environmental issues as well as their transmission footprint, and considers whether or not they are proxy projects (potential projects that have been identified but have no investor willing to apply for permits and sponsor the project), their proximity to sensitive lands, and whether the project is located on federal lands. Projects located on federal lands could mean that they may take more time to permit and construct.

The results of the RETI and Aspen studies have been incorporated into the RES Calculator in the form of cost modifiers related to each renewable project. The modifiers are not only based on the results of the scoring mechanism, but also on aspects related to the value of a project's energy (e.g., on-peak availability, reliability, etc.) and the probability that a project will obtain permits necessary to achieve operation by 2020. By using this type of ranking system, projects are selected not only on the costs associated with generating and delivering a MWh to a load center, but also on the value of including that resource in the California energy mix and the relative ease of obtaining permits for a project with a low environmental footprint or ranking score.

c. General Inputs and Assumptions

The RES Calculator is supported by a set of inputs and assumptions based on best available data and work performed by the California energy agencies, ARB, and E3 during the development of the proposed RES regulation. These parameters have been transformed into Renewable Energy Scenarios using a process that is built into the RES Calculator's logic and functionality. The RES Calculator processes multiple parameters such as the energy load demand forecast, environmental concerns, and cost impacts to estimate the most reliable renewable resources anticipated to come on line by 2020. The following explains several general inputs and assumptions that provide an overview of the RES Calculator's functionality. A detailed description of the differences between the RPS and RES Calculators and the technical inputs and assumptions used to develop both calculators can be found in Appendix B.

d. Resource Ranking, Availability, and Performance

The RES Calculator ranks and selects renewable resources from 31 resource zones within California and 13 resource zones located in out-of-state regions but within the WECC. Each ranking relies on resource availability and performance attributes from four major types of information sources:

1. For in-state resources, the RES Calculator uses CREZs identified in the RETI Phase 1B report to group renewable resources for delivery to one of two major load centers in California. For resource zones that originate outside of California, the RES Calculator uses a dataset developed by E3 in 2007 for the CPUC and Western Electric Industry Leaders (WEIL) Group. The RES Calculator chooses both the in-state and out-of-state resource zones as groups of renewable resources based on a highest-ranking score method.

2. The RES Calculator incorporates the most recent publicly-available version of the CPUC IOU Contract Classifications database that contains an up-to-date evaluation of renewable energy projects located in California and throughout the WECC. In addition, E3 incorporated resources that the POUs report to the CEC on a regular basis (both currently operational and planned for construction by 2020). Resource zones with a large amount of interest in commercial development are given a credit that moves those zones towards a higher ranking score.

3. For distributed solar generation (generation that is distributed throughout a region but has no specific location and does not require substantial transmission), E3 and Black & Veatch developed estimates of potential solar generation on large rooftops in urban areas and near remote, rural substations to portray the amount of solar DG generation available in 2020. These resources are included as a separate group of resources that reduces the need for the construction of large transmission lines. E3 assumes that the

distribution system can accept the interconnection of approximately 6,000 MW of rooftop or urban ground-mounted solar resources and 9,000 MW of remote solar resources (20-40 MW projects).

4. The RES Calculator assumes that, in most cases, new high-voltage transmission lines must be constructed to deliver new renewable energy to California's largest load centers. The cost of these lines, determined using an E3 transmission costing tool,[h] is included as an annual cost, levelized over the life of the resource. The transmission cost factors into the ranking cost for a group of resources transmitted across a particular line.

   In order to perform the analysis, the RES Calculator converts all costs to an annual, $/MWh levelized cost which includes a nominal price that if collected each year over the life of the resource, would completely cover the costs of installing and operating a particular renewable resource. For renewable energy resources, this levelized cost is spread over the annual generation of the resource to generate a per-MWh cost of the resource. For transmission lines, this annual levelized cost is spread over the capacity of the transmission line which represents the annual cost of a unit of capacity for a particular transmission line run.

2. Differences Between the RPS and RES Calculators

This section describes differences between the RPS Calculator used by CPUC for its 33 percent Implementation Analysis and the RES Calculator used to estimate resource requirements for the proposed RES regulation. Both calculators were designed by E3 to estimate a cost and resource mix needed to meet a 33 percent renewable supply in 2020 and use the same modeling logic and operating parameters. The primary differences between the calculators are that the RES Calculator has been updated to include current renewable contracting activity, costs, and resource characterizations, and has been modified to accommodate changes related to the proposed RES regulation. Table V-7 summarizes the differences between the two calculators. A full listing of all the modifications can be found in Appendix B (Differences between the RPS and RES Calculators).

[h] The E3 Transmission Costing Tool is available at http://www.arb.ca.gov/energy/res/res.htm

Table V-7
Differences between the RPS and RES Calculators

RPS Calculator	RES Calculator
Uses 2007 IEPR Load Demand Forecast	Uses 2009 IEPR Load Demand Forecast
No criteria pollutant estimates	Includes criteria pollutant estimates
Calculates effect of CO_2 compliance on electricity ratepayers	Calculates all regulated electricity sector CO_2 emissions
Uses 2009 renewable cost and resource characterizations	Uses 2010 cost and resource characterizations for solar PV, wind, natural gas prices, and biomass/biogas
Uses 2009 CPUC Renewable Contract Database to estimate new resources	Uses 2010 CPUC Renewable Contract Database to estimate new resources
Does not include POUs	Includes POUs in the 20 percent scenario and functionality to omit small utilities less than 200,000 GWh
No Out-of-State RECs	New Out-of-State RECs module included

3. Scenario Analyses

This section presents a scenario analysis developed with use of the RES Calculator to evaluate a range of energy mixes that could power the California electricity grid in 2020 in compliance with the proposed RES requirement. The scenarios presented reflect the most current information available related to State utility contracting activity, the current forecasted load for 2020, and modifications to inputs and assumptions as reported by the California utility agencies and incorporated by E3 into the RES Calculator. The scenarios encompass a range of possible outcomes that account for changes in load demand due to varying degrees of energy efficiency, combined heat and power (CHP), and distributed solar generation (solar DG) which will be presented throughout this section. Although the scenarios may not fully incorporate parameters such as ideal energy load balancing under optimal conditions, these aspects are under evaluation and have been incorporated to the greatest extent possible.

For this analysis, a total of four renewable scenarios were modeled. These include the 20 Percent RPS (business as usual case) and the 33 Percent RES scenario, which includes the use of unlimited, unbundled RECs. In addition, two other scenarios were modeled, including an Incremental In-State Only scenario

to evaluate the impacts of requiring all additional resources above a 20 percent RPS level to come from in-state resources only, and a 33 Percent Bundled RECs Only scenario for comparing differences between the use of bundled and unbundled RECs. Table V-8 lists the four scenarios modeled and highlights the differences between scenarios.

Table V-8
Renewable Scenario Modeling Runs Conducted with the RES Calculator

	20 Percent RPS	Proposed 33 Percent RES	33 Percent Bundled RECs Only	Incremental In-State Only
Compliance Requirements	20% by 2010	33% by 2020	33% by 2020	In-State only above RPS
REC Limits	No Unbundled RECs[i]	Unlimited Unbundled RECs	Bundled RECs Only	No Out-of-State RECs
Delivery Requirements	Within 1-year	No Delivery	Within 1-year	N/A

The results of the Incremental In-State Only scenario are presented in Chapter XI (Alternatives Analysis), which compares the environmental and economic impacts to the Proposed 33 Percent RES scenario presented in this section. The results of the 33 Percent Bundled RECs Only scenario are not presented, because those results are identical to the results presented for the 33 Percent RES scenario that includes the use of unlimited unbundled RECs. The reason that the two results are identical is due to the way that the RES Calculator selects renewable resources. In both a bundled and unbundled scenario, the RES Calculator assumes that a Load Serving Entity (LSE) must still purchase an equivalent amount of energy to accompany an unbundled REC to serve load. Additional discussion on the differences between the bundled and unbundled REC scenarios can be found below in Section (e).

a. High and Low Load Conditions

Each scenario evaluated in this analysis is based on RES Calculator output that is separated into two primary categories referred to as High Load and Low Load conditions. These conditions represent the highest and lowest amounts of electricity projected to be needed to serve the California grid in 2020 and encompass a range of potential pathways to meet the proposed RES regulation. Table V-9 summarizes these two load conditions. The subsequent discussion

[i] On May 6, 2010, the CPUC Decision regarding the use of Tradable RECs was stayed. For more information see http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/117847.pdf

details each of the Scoping Plan measures and identifies the amount of energy that is expected to be reduced from the overall energy demand in 2020 as a result of each measure.

Table V-9
High and Low Load Conditions

High Load	This load condition, also considered the "upper bound" condition, uses the results of the 2009 IEPR load forecast with no additional modifications. The 2009 IEPR forecast uses historical data to draw assumptions and includes embedded values for Energy Efficiency, CHP and Solar DG, including rooftop and wholesale sources, but does not include full load demand reductions from the electricity sector measures as identified in the Scoping Plan. The high load demand used in each scenario is 301,000 GWh of retail sales in California.
Low Load	This condition reflects modifications to the 2009 IEPR forecast that reduces the grid's load demand in 2020 from full implementation of the Scoping Plan measures related to Energy Efficiency, CHP, and Solar DG energy. The result is a lower demand load projected for 2020 as compared to the 2020 High Load condition. The low load demand used in each scenario is 263,000 GWh of retail sales in California.

(1) Energy Reductions from Scoping Plan Measures

There are three Scoping Plan measures for reducing statewide electricity demand: Energy Efficiency, CHP, and solar distributed generation (Solar DG). These measures have been incorporated into the High and Low Load conditions. The expected reductions from the measures have been modified since the original release of the Scoping Plan to reflect more recent analysis. The RES Calculator has been modified to reflect this current information. The modifications were prepared and finalized by the California energy agencies and approved by the CPUC for release to RETI on January 13, 2010.[32] These assumptions were developed in an effort to coordinate infrastructure planning efforts at the CEC, CPUC, and ARB while also supporting efforts to inform CAISO's 33 Percent RPS Operational Study. Combined, these measures would reduce an estimated 38,000 GWh of California's retail sales in 2020 after factoring in decrements for transmission line losses. The measures are fully incorporated into each of the low load scenarios, while the high load scenarios only use partial amounts of these reductions that are imbedded within the 2009 IEPR energy demand forecast.

Energy Efficiency

Energy Efficiency is a strategy designed to reduce greenhouse gas emissions in the electricity sector. An energy efficiency and conservation program also reduces electricity consumption, makes businesses more competitive, and allows consumers to save money. These reductions result from building improvements including "Zero Net Energy" buildings which are designed with highly energy-efficient building construction, state-of-the-art appliances and lighting systems, and high performance windows that reduce a building's load and peak requirements. In addition, these improvements can include on-site solar water heating and renewable energy, such as solar photovoltaic, to meet remaining energy needs. Overall, these improvements are estimated to reduce California electricity retail sales by about 22,000 GWh in 2020.

Combined Heat and Power

The RES Calculator includes a 2020 Low Load reduction resulting from behind-the-meter CHP (electricity used on-site that may not be delivered to the grid). Such systems are installed at large facilities such as hospitals, large buildings, or factories. In these cases, a facility installs a highly efficient CHP system designed to serve its own energy, thereby reducing the need for electricity from the grid. The widespread use of efficient CHP systems would also help displace the need to develop or expand existing power plants and reduce burden on the transmission grid. Overall, behind-the-meter CHP is expected to reduce California's electricity retail sales by 14,000 GWh in 2020.

Solar Distributed Generation

The RES Calculator incorporates a low load reduction of about 2,000 GWh due to the use of residential and commercial rooftop solar DG in 2020. These systems reduce electricity load by generating on-site electricity during daylight hours and reducing the need for transmission across the California grid. The solar DG estimate was projected by taking the average annual solar DG capacity installation costs pending for 2008 and 2009 for the IOUs, and the capacity costs installed in 2008 for the POUs. These results are carried forward until 2016 when both the California Solar Initiative and New Solar Home Programs are currently scheduled to end. Solar DG capacity for years between 2017 and 2020 were derived by allowing the installed capacity to grow at the historical rate of Solar DG electricity consumption through 2020.

b. 20 Percent RPS Scenarios

The 20 percent RPS Scenarios, also referred to as the "reference case scenarios," were developed under high and low load conditions to serve as a benchmark for comparing incremental differences between the current RPS program and the proposed 33 percent RES regulation in 2020. These scenarios

were developed with use of the RES Calculator and incorporate changes related to inclusion of the 2009 IEPR forecast and updates previously discussed in Section 2 of this analysis. Both scenarios represent current RPS program requirements, including energy delivery within one calendar year, and the disallowance of unbundled out-of-state RECs. Since the scenarios incorporate current information related to the 2009 IEPR forecast, IOU contracting activity, and new resource cost and characterizations, the 20 percent scenarios represents the most current estimate of a likely 20 percent renewable energy mix in 2020. As such, these scenarios served as an up-to-date benchmark for evaluating incremental differences when increasing renewable energy levels from the current 20 percent RPS to the proposed 33 percent energy level.

c. 33 Percent RES Scenarios

The 33 Percent RES Scenarios represent a resource mix capable of powering the California electricity grid in 2020 in accordance with the proposed RES regulation. The scenarios illustrate the use of in-state and out-of-state renewable resources above those required to meet a 20 percent RPS requirement. Both scenarios incorporate the most current renewable energy contracting information, cost data, and renewable resource characterization available. The primary difference between the 33 Percent RES and the 20 Percent RPS scenarios are the addition of modifications inherent to the proposed RES regulation, including the incorporation of unlimited out-of-state RECs, the inclusion of POUs and RES Qualifying POU resources, and a partial exemption for utilities that supply less than 200,000 GWh retail sales annually. Therefore, the 33 Percent RES Scenarios represent staff's most accurate depiction of a 33 percent renewable resource mix in 2020 in accordance with the proposed RES regulation.

d. Comparison of 20 Percent RPS and 33 Percent RES Scenarios

This section presents the results of the 20 Percent RPS and 33 Percent RES scenarios and an analysis of the differences between results. Tables V-10 and V-11 illustrate the incremental differences between the scenarios under both the high and low load conditions. Tables V-12 and V-13 illustrate the amount of renewable energy that comes from in-state and out-of-state sources under the same high and low load conditions. All values presented include transmission line losses.

Tables V-10 and V-11 present incremental differences in renewable generation from each of the seven renewable source categories under the 20 percent and 33 percent scenarios. The figures represent the incremental amount of new renewable generation required under both scenarios. The high load scenario (Table V-10) reveals that the largest incremental differences are due to geothermal, solar thermal, and wind energy resources, where in all cases the amount of energy from these resources increases when moving to a 33 percent

energy level. The reason is because the RES Calculator selects more of these resources than others due to current contracting activity and the low cost and relative ease of integrating these resources in 2020. Table V-10 also shows an increase in the use of solar PV, which is a result of the continued use of rooftop solar in California and changes made to the costs and resource characterization of this resource. Finally, the high load predicts some increase in the use of out-of-state biomass due to the ability to integrate these resources at a relatively low-cost compared to other resources.

Table V-11 presents the low load scenarios and identifies similar results as those displayed under the high load condition. However, the low load indicates no additional use of geothermal resources as compared to the high load condition. The reason is because under a high load condition, the RES Calculator draws resources from the Imperial North CREZ, a region that is heavily developed with the use of geothermal energy, and therefore builds a resource mix relying heavily on this resource. Under the low load condition, the RES Calculator did not select resources from the Imperial North CREZ.

Tables V-12 and V-13 present a comparison of the in-state and out-of-state renewable source categories and indicates the incremental increase in energy under both the high and low load conditions. Under the high load condition, Table V-12 indicates only small, incremental increases in out-of-state biomass and wind resources. The reason for such a small increase (about 4 percent) is because the RES Calculator relies on current renewable contracting activity and the majority of contracts are for resources located within California. Table V-13 illustrates a similar outcome under the low load condition. However, under the low load condition, two additional resources for out-of-state biogas and small hydro resources are included. The reason for the addition of these resources is also based on current contracting activity and the low cost of integrating these resources into the California electricity system.

Table V-10
Comparison of 20 Percent RPS and 33 Percent RES Scenarios, High Load

Renewable Resource	20% RPS in 2020 (GWh)	33% RES in 2020 (GWh)	Difference between 20% RPS and 33% RES (GWh)	Percentage of Incremental Renewable Mix
Biogas	1,320	1,320	0	0.0%
Biomass	1,160	1,390	224	0.6%
Geothermal	7,220	18,800	11,500	31.9%
Small Hydro	757	757	0	0.0%
Solar PV	1,090	3,400	2,270	6.3%
Solar Thermal	4,940	16,300	11,300	31.3%
Wind	13,500	24,300	10,800	29.9%
Total	30,000	66,300	36,100	100.0%

Table V-11
Comparison of 20 Percent RPS and 33 Percent RES Scenarios, Low Load

Renewable Resource	20% RPS in 2020 (GWh)	33% RES in 2020 (GWh)	Difference between 20% RPS and 33% RES (GWh)	Percentage of Incremental Renewable Mix
Biogas	1,310	1,330	16	0.0%
Biomass	1,150	1,390	236	0.8%
Geothermal	7,170	7,170	0	0.0%
Small Hydro	692	757	65	0.2%
Solar PV	1,020	3,200	2,180	7.4%
Solar Thermal	4,260	15,500	11,200	38.2%
Wind	8,590	24,300	15,700	53.4%
Total	24,200	53,700	29,400	100.00%

Table V-12
Comparison of In-State and Out-of-State Resources Used in the 20 Percent RPS and 33 Percent RES Scenarios, High Load

Renewable Resource	20% RPS in 2020 (GWh)			33% RES in 2020 (GWh)			Incremental Increase (GWh)	
	In-State	Out-of-State	% In-State	In-State	Out-of-State	% In-State	In-State	Out-of-State
Biogas	1,310	16	99%	1,310	16	99%	0	0
Biomass	1,150	12	99%	1,150	236	83%	0	224
Geothermal	6,540	680	91%	18,100	680	96%	11,500	0
Small Hydro	214	543	28%	214	543	28%	0	0
Solar PV	1,060	22	98%	3,330	22	99%	2,270	0
Solar Thermal	2,500	2,440	51%	13,800	2,440	85%	11,300	0
Wind	7,620	5,860	57%	17,300	6,990	71%	9,600	1,130
Total	20,400	9,570	68%	55,200	10,900	84%	34,700	1,350

Table V-13
Comparison of In-State and Out-of-State Resources Used in the 20 Percent RPS and 33 Percent RES Scenarios, Low Load

Renewable Resource	20% RPS in 2020 (GWh)			33% RES in 2020 (GWh)			Incremental Increase (GWh)	
	In-State	Out-of-State	% In-State	In-State	Out-of-State	% In-State	In-State	Out-of-State
Biogas	1,310	0	100%	1,310	16	99%	0	16
Biomass	1,150	0	100%	1,150	236	83%	0	236
Geothermal	6,490	680	91%	6,490	680	91%	0	0
Small Hydro	214	478	31%	214	543	28%	0	65
Solar PV	999	22	98%	3,170	22	99%	2,180	0
Solar Thermal	1,820	2,440	43%	13,000	2,440	84%	11,200	0
Wind	2,730	5,860	32%	17,300	6,990	71%	14,500	1,130
Total	14,700	9,480	61%	42,600	10,900	80%	27,900	1,450

As part of this analysis, staff compared the results developed as part of the Out-of-State Renewable Generation analysis (Table V-6) with the results developed with use of the RES Calculator under the 33 Percent RES High Load scenario (Table V-11). The analysis shows that the results are similar for nearly all renewable categories with differences attributed to the way the RES Calculator selects groups of renewable resources from individual CREZs (note: Table V-6 compiles solar PV and solar thermal resources into a single resource category titled "solar"). The largest differences are for biomass and wind sources.

For biomass, E3 and ARB concluded that the difference is due to the fact that E3 increased the costs of some biomass projects to include the costs of purchasing offsets needed to construct those projects in certain California air districts. Therefore, the RES Calculator did not select all of the biomass projects simply because the costs of the projects appears to be too high. For wind, E3 and ARB concluded that that the difference is primarily due to the fact that a number of wind contracts used in the Out-of-State Renewable Generation analysis are for out-of-state short-term contracts (less than 10 years in duration) while the RES Calculator only selects contracts longer than 10 years in duration. E3 incorporated long-term contracts only in an effort to best-predict a reliable resource mix in 2020. It is possible that some of the short-term wind contracts may not be renewed by 2020. Therefore, the overall total for new out-of-state resources is lower with results produced with the RES Calculator.

e. Differences between Bundled and Unbundled RECs

E3's modeling results find no meaningful distinction – within the context of its economic modeling – between a scenario in which a utility purchases both the energy output and a REC from a renewable energy resource (bundled REC scenario) and one in which the utility purchases only the REC (unbundled REC scenario). E3 models renewable resources as Power Purchase Agreements (PPAs) between a renewable energy developer and a credit-worthy California LSE. In both the bundled and unbundled REC scenarios, the RES Calculator prices the REC portion of the transaction at the "net" cost of the renewable resource. This is the cost of developing the resource, including a fair equity return to the developer based on a set of standard financing assumptions, minus the market value of the energy and capacity services that the resource provides.

In an unbundled REC scenario, the LSE purchases only the REC and must match it with a purchase of energy from the CAISO market to serve load. In a bundled REC scenario, the LSE also purchases the energy from the developer at the local market value and resells it in the local market at the same price. No profit or loss is assumed for the energy portion of the transaction. Therefore, the value to electric ratepayers and the costs to integrate resources are identical and the RES Calculator selects an identical renewable resource mix.

f. Results of Incorporating Unbundled Out-of-State RECs into the 20 Percent and 33 Percent Scenarios

In response to ARB's proposal to allow for unlimited unbundled RECs in the proposed RES regulation, E3 incorporated a new REC module into the RES Calculator. The RES Calculator now allows an unlimited number of out-of-state unbundled RECs to be used under the 33 Percent RES scenario. As part of the development of the new module, E3 estimated a reasonable upper-bound on the amount of wind energy that could be integrated into the WECC without requiring large investments in new transmission lines or wholesale changes in grid operations. After accounting for local demands stemming from other states' RPS goals, E3 estimated that up to 9,000 MW (about 26,000 GWh) of wind energy could be developed in other jurisdictions for the purpose of creating RECs to sell into the California market. These resources were made available for selection by the RES Calculator for use in California, and could have been selected if the costs of those transactions were lower than competing in-state resources.

The RES Calculator selected a substantial quantity of bundled out-of-state RECs in the 20 Percent RPS scenario, including wind, biomass and geothermal resources. However, only about 1,400 GWh of incremental out-of-state REC transactions were selected for the 33 Percent RES scenario, and the majority of those out-of-state resources were for contracted wind power. The reason is due to procurement and contracting activity that has already taken place in California. California utilities have signed contracts for delivery of more than 50,000 GWh of renewable energy by 2020. For the purpose of this modeling exercise, the ARB has assumed that these resources will be developed on schedule. Therefore, there is little need for utilities to contract for incremental out-of-state resources.

g. Summary

The information presented in this analysis provides a description of the tools and methodologies used to evaluate a potential 33 percent renewable resource mix in 2020 needed to satisfy the proposed RES regulation. The primary tool used to conduct the analysis was the RES Calculator. This tool was outfitted with modules to accommodate the proposed regulation, along with updates to reflect the current costs and resource characterizations of renewable resources, and the current status of renewable energy contracting activity. The results provided two sets of renewable energy scenarios that illustrate a comparison of the most current estimate of a 20 percent RPS resource mix and that of the proposed 33 percent RES. Although the scenarios may not fully incorporate parameters related to permitting, construction, and ideal load balancing situations, these aspects are under evaluation and have been incorporated to the greatest extent possible.

The results conclude that there are adequate renewable resources available in 2020 to meet the proposed 33 percent requirement and that nearly all resources

(between 80 and 84 percent) could be available from within California. The results show primarily an increase in wind, solar thermal, and solar PV resources when going from a 20 percent to a 33 percent level, and that only small incremental amounts of out-of-state resources (between 1,360 and 1,450 GWh) are needed when going from a 20 percent to a 33 percent level, even with the ability to use unlimited out-of-state RECs. The results also conclude that there is no economic distinction in results between a bundled and unbundled REC scenario. This is because in both cases, the RES Calculator assumes that an equivalent amount of energy must be purchased and delivered by a LSE. This resulted in the same costs to electric ratepayers and an identical set of renewable resources selected.

D. Transmission and Grid Operation Considerations for Integrating Renewable Generation

The CPUC's *33% Renewables Portfolio Standard Implementation Analysis Preliminary Results* report demonstrates that full compliance with a 33 percent renewable target by retail sellers by 2020 is ambitious and will be challenging, especially in terms of building adequate new transmission in a timely manner. In addition, there will be challenges to maintain or balance grid operations due to the variability and daily or seasonal generation profiles of some renewable resources such as wind and solar. This section provides an overview of California's transmission system and the modifications that would be needed to it to integrate new renewable generation into the grid.

1. Overview of California's Transmission and Distribution System

California's power transmission grid is composed of high-voltage transmission lines that feed electricity to lower-voltage distribution lines. This system connects thousands of generation facilities to retail customers. The high-voltage lines deliver electricity from the generators to substations where the electricity voltage is dropped to safer levels for retail customers. Then, the distribution lines deliver the low voltage electricity from the substations to the electricity consumers. Overall, the grid is reliable, but it must be able to support periods of peak demand.

To avoid electricity outages due to peak demand exceeding supply, the agencies that regulate the State's electricity grid forecast trends in electricity consumption. This includes the impact of technology changes (such as electrification of transportation) and State mandates, such as investments in end-use energy efficiency. These forecasts are used to plan the expected load and determining if load-serving entities have procured enough energy to satisfy the load. To meet these requirements, the developers of transmission and generation make investments in generation, transmission, and distribution. The State's energy entities (CEC, CAISO, and CPUC) are currently working on simulations of power

system operations that will provide additional information to support delivering variable and remote renewable power, such as wind and solar.

In several of California's cities and towns, including part of Los Angeles and the Bay Area, there is a lack of sufficient transmission lines to deliver all the electricity needed by the retail customers within the area and maintain reliabillity. In addition, there is not enough generation within the area to meet the total electricity need. Therefore, electricity is needed from generation within the area and generation from outside the area (imports). The generation within and nearby populated areas is typically natural gas generation that emits GHGs and criteria pollutants. However, until sufficient renewable energy and possibly storage can be built within these transmission constrained areas, or additional transmission to provide sufficient energy, these gas-fired generators will be required to continue to operate to ensure reliability.

Another issue that must be evaluated is that the inertia of renewable generation is generally less than the inertia of fossil-fueled generation that is expected to be displaced by renewable generation. For the electrical grid, inertia can be defined as a generator's stored energy that resists speed changes. The inertia of a power generator stabilizes the frequency of the transmission and distribution system when a large deficiency of generation occurs (i.e., the unexpected loss of a generator or a large load is added). This is another potential constraint on the retirement of gas generation.

As stated above, areas are richest in potential renewable energy, such as wind, solar, and geothermal, are often remote from population concentrations. Many of the proposed renewable generation projects are planned for locations that currently lack sufficient transmission capacity to deliver the renewable energy to California's distribution lines and on to retail customers. The need for additional transmission facilities to access renewable-rich resource areas has been identified by State agencies as a requirement for attaining a 33 percent renewable energy goal.

In the past, the installation of transmission has been met with resistance due to cost, environmental concerns, and access to right-of-way. To address these issues, several entities including the Renewable Energy Transmission Initiative (RETI) (a joint initiative of the CPUC, CEC, ISO and other stakeholders), CAISO, CEC, and Western Governors' Association (WGA) have been studying the location of high quality renewable energy zones that are reasonably close to major transmission lines and would have a low environmental impact. In particular, in the last few years, multiple renewable resource and demand scenarios for 33 percent RPS have been studied to determine what transmission lines or transmission upgrades would be needed, taking into account the location of the renewable source, the electricity demand, and the type of renewable generation installed. In addition, the scenarios will help determine other transmission options if planned transmission lines are not built. Appendix B

contains descriptions of some efforts to evaluate the necessary modifications to California's transmission system, and the necessary modifications to the transmission system of the entire WECC.

The studies do not yet provide a consensus regarding the likely transmission projects that are needed to meet a 33 percent renewable energy target or will be constructed for future demand growth. The reasons for the lack of a consensus are the significant uncertainty in all aspects of renewable development, including the environmental risks, the economic costs, the commercial interest and commitment, and the future regulatory rules. To bring all the needed renewable generation to retail customers, all the studies have concluded that numerous transmission modifications will be needed and will cost billions of dollars. In addition, the CPUC has pointed out that delays in permitting and construction of some of the proposed transmission lines, due to cost, permitting issues, local opposition to the right away, and other factors, could delay achievement of the 33 percent RPS by 2020.

Additionally, nearly all the studies assume that the electricity output of all out-of-state renewable generation must be delivered to California, as is required in the RPS. That is, the REC and the electricity generated must be bundled together. If the out-of-state renewable generation is not required to be delivered to California, but delivered to out-of-state retail customers that are closer to the generation (unbundled RECs), there could be a significant transmission cost savings since fewer transmission modifications would be needed. Additionally, since the transmission system modifications are more modest for unbundled RECs, and may be easier to permit and construct in other western states, it's more likely that the necessary transmission modifications would be completed in a timely basis. This would increase the feasibility that the 33 percent renewable goal could be attained by 2020.

2. Integration of Renewable Generation into the Grid

The analysis shows that wind and solar generation represent a significant portion of the total renewable generation today, about 3,000 GWh in-state, or about 15 percent of the total in-state generation from renewable resources. If all the contracts for the large IOUs and POUs are fulfilled, the generation expected from wind and solar will increase ten fold by 2020 and represent over 50 percent of all in-state renewable generation. The following discussion presents the issues associated with integrating such a large amount of wind and solar generation into the grid, and how balancing authorities like CAISO will try to resolve these issues.

There is significant out-of-state wind and solar renewable generation already being delivered to California. Currently, this electricity is shaped and firmed prior to being delivered to California. Shaping and firming refer to using additional power or storage to make the variable generation constant and packaging the

variable generation so that it can be imported into the transmission system. Hence, the balancing authorities that schedule imports can treat these imports the same as other imports into California. However, the ISO has begun a process to pilot and then expand what are called "dynamic transfers," which are imports for which the ISO would provide the integration requirements using in-state resources.

a. Wind and Solar Generation Operating Characteristics

Wind and solar generation are considered variable generation in that the generation from these resources can vary from minute to minute—largely due to changes in meteorological conditions. In addition, this variability is difficult to forecast. On average in California, wind production is an overnight resource, with an increase in production in the evening and a decrease in the mid-morning. Forecast errors are due to the difficulty in forecasting wind, particularly during storms, as well as clouds masking solar radiation that cause a drop in solar generation—after the clouds pass, the generation goes up sharply. Finally, over-generation, which is most likely to occur during the over-night hours, can occur occasionally when there is more wind generation than is needed, and other generators cannot be further decreased.

b. Operational Integration of Wind and Solar Generation

All balancing authorities are required to provide ancillary services for various reliability and operating purposes.[33] One service provided as part of ancillary services is the matching of supply (electrical generation) to demand on a minute-by-minute basis. Each day, the balancing authority estimates the generation needed for the next day on a hour-by-hour basis. At the appointed hour, the minute-by-minute scheduling allows an exact match of supply to demand. If the supply is short of the demand, the balancing authority must request a generator(s) to increase production in the upward direction to match the demand. Conversely, if the supply is projected to be greater than the demand, the balancing authority will request that a generator(s) reduce production.

CAISO has completed a study of the operational impact of integrating 20 percent renewable generation, pursuant to the goals of the RPS.[34] This study was based upon integrating 6,700 MW of wind generation capacity (2,600 of this capacity is from existing wind generation as of 2006), with the new wind generation located in the Tehachapi area. Among the many conclusions and recommendations provided by this study, CAISO indicated that additional resources may be necessary to backup variable generation than are currently procured to match supply to load. Additionally, the portfolio of these additional resources must include various operational capabilities, including the ability to start and stop rapidly and the ability to change generation production rapidly in the upward or downward direction.

The capability to address energy to load imbalances within the hour depends on the operational capability of the generation fleet. Due to the increased generation from wind and solar, CAISO expects the energy imbalance needs will increase substantially over the next ten years. Some of these needs can be attributed to the RPS program and some of the need can be attributed to the proposed RES program. For the area under CAISO's jurisdiction, CAISO currently procures, on a daily basis, about 350 MW of generation that can quickly increase generation on an automated basis and another 350 MW of generation capacity that can similarly quickly decrease generation. There is currently about 12,000 MW of capacity certified to provide this service, although many units will be subject to once-through cooling regulations and may be retired or be repowered. The expectation is that based on the available generation that can provide this service, there appears to be enough existing eligible generation capacity, 12,000 MW, that can be added to the amount typically procured by the CAISO, 350 MW, to satisfy the need for additional resources to backup variable renewable generation at the 20 percent RPS and possibly also at the 33 percent RPS. However, these expectations are being validated by CAISO in the 33 percent integration study.

The generation used to provide this service includes combined cycle combustion turbines (CCCTs), combustion turbines (CTs), and hydroelectric generation. These types of generation can quickly change power output. CCCTs and CTs that are on-line can change output quickly. Even if CCCTs are at their continuous operation capacity for generation output, they are capable of providing additional MW for short periods. CTs can quickly start-up and be available to provide generation within a short time period. Hydroelectric generation can provide the fastest changes in generation output, at a rate, in terms of MW per minute, considerably higher than natural gas generation.

The current system of generators that are used to match supply to load is able to firm and shape the current amount of in-state renewable generation. That is, when the variable generation does not provide the expected amount of generation, then a CCCT or CT could increase operation to "make-up" the generation that was not produced from the variable renewable resource or decrease operation when the variable renewable resource provides more generation than expected. However, with the addition of significantly more variable generation to the grid by 2020, the issues posed by the variable generation discussed above will be more pronounced.

To integrate large amounts of variable renewable generation, the generation used as backup must be able to rapidly increase and decrease production. Both wind and solar generation can have sudden increases or decreases in generation. To compensate, the generators that will provide backup will need to be able to increase or decrease generation in concert with the renewable generation. Within the CAISO area, about 7,000 MW of the certified capacity can change generation at a rate of 10 MW per minute or greater. CCCT and CT

generation represent about 2,400 MW and can change generation at a rate between 10 and 30 MW per minute. In general, CTs can change generation much more rapidly than CCCTs. The remaining 4,600 MW of capacity is from hydroelectric sources—2,800 MW of this generation can change generation at a rate greater than 100 MW per minute. CAISO is currently reviewing, as part of its 33 percent integration study, whether the existing fleet can provide the necessary services to backup variable renewable generation. Staff notes that other balancing authorities within California have different resources available and may have more limited options toward firming and shaping variable renewable resources. For example, LADWP provides backup generation to renewable sources with a combination of one CCCT and hydroelectric generation.[35] When more variable generation is added to the grid, LADWP believes it will need to add CTs.

The operational aspect of integrating renewables will clearly have an impact on GHG emissions. While the displacement of fossil energy by renewable energy will reduce GHG emissions, the need to keep fossil resources available for reserves and the balancing functions discussed above will decrease some of the emissions benefits from renewable energy. The exact GHG impact is still being simulated in various studies, including those conducted by the ISO.

The need for additional generators to provide rapid response for variable renewable generation, and in some cases the associated GHG emissions, can be mitigated with: 1) the installation and use of storage devices such that any additional generation above a certain level can be saved for later use when the generation is needed; 2) added operational flexibility where the resource can respond to operating need—for example, reducing generation when the generation is not needed by the utility; and 3) addition of backup capabilities, such as a solar tower power plant using a boiler to backup the solar generation.

In summary, variable renewable generation can be integrated into the grid if the balancing authority has the necessary generation, such as a combination of CCCT, CT, or hydroelectric generation. Balancing authorities are evaluating the types of resources that are needed to successfully integrate variable generation into the grid expected in 2020. CAISO, the largest balancing authority in California, is conducting a study to determine the types and amount of resources needed to fully integrate this generation into the portion of the grid they manage. This study is expected to be completed by the end of 2010.

REFERENCES

[1] American Wind Energy Association, 2010. 2009 U.S. Wind Industry Annual Market Report: Rankings, http://www.awea.org/pubs/factsheets/Industry_Rankings_Factsheet.pdf

[2] California Energy Commission, 2008. Fast Facts About Wind Energy, http://www.energy.ca.gov/wind/windfacts.html

[3] California Energy Commission, 2005. California Wind Resources. http://www.energy.ca.gov/2005publications/CEC-500-2005-071/CEC-500-2005-071-D.PDF.

[4] Renewable Energy World, 2009. *Another Wind Farm for Tehachapi Pass*, http://www.renewableenergyworld.com/rea/news/article/2009/10/another-wind-farm-for-tehachapi-pass.

[5] California Energy Commission, 2010. Large Solar Energy Projects, http://www.energy.ca.gov/siting/solar/index.html

[6] Sandia National Laboratories (National Solar Thermal Test Facility), 2006. Desirable Features of Power Towers for Utilities, http://www.sandia.gov/Renewable_Energy/solarthermal/NSTTF/feature.htm

[7] California Energy Commission (Prepared by Ryan Wiser and Mark Bolinger), 2005. Projecting the Impact of State Portfolio Standards on Solar Installations, http://www.cleanenergystates.org/library/ca/CEC_wiser_solar_estimates_0205.pdf

[8] California Public Utilities Commission, 2010. RPS Project Status Table, http://www.cpuc.ca.gov/NR/rdonlyres/9AA867DE-3745-48D1-A740-B7B0BC2627A4/0/RPS_Project_Status_Table_2010_May.XLS

[9] California Energy Commission, 2010. Geothermal Energy in California. http://www.energy.ca.gov/geothermal/index.html

[10] University of California Davis, 2004. California Biomass Power Plants, http://groups.ucanr.org/WoodyBiomass/documents/Industry_Information11948.pdf.

[11] Renewable Energy Ventures, LLC, 2009. Fluidized Bed Combustion, http://www.fluidizedbedcombustion.com/

[12] Air Resources Board, 2009. Staff Report: Initial Statement of Reasons for the Proposed Regulation to Reduce Methane Emissions from Municipal Solid Waste Landfills, http://www.arb.ca.gov/regact/2009/landfills09/isor.pdf

[13] Western Governors' Association, 2008. Strategic Assessment of Bioenergy Development in the West Task 2: Bioenergy Conversion Technology Characteristics.

[14] International Energy Agency Bioenergy (Prepared by Swedish Gas Center and Nova Energie GmbH), 2006. Biogas Upgrading to Vehicle fuel Standards and Grid Injection, http://www.iea-biogas.net/Dokumente/upgrading_report_final.pdf

[15] California Energy Commission, 2008. Ocean Energy, http://www.energy.ca.gov/oceanenergy/index.html

[16] California Independent System Operator, 2007. Integration of Renewable Resources. http://www.caiso.com/1ca5/1ca5a7a026270.pdf

[17] California Energy Commission, 2009. Total Electricity System Power, http://www.energyalmanac.ca.gov/electricity/total_system_power.html

[18] California Public Utilities Commission, 2008. PG&E's August 2009 RPS Compliance Report, http://www.cpuc.ca.gov/NR/rdonlyres/EBE57831-83F3-45A1-A6AD-859F3B77A64C/0/IOU_August_2009_RPS_PDSR_Public_PGE.pdf

[19] California Public Utilities Commission, 2009. Southern California Edison August 2009 Compliance Report, http://www.cpuc.ca.gov/NR/rdonlyres/E045EB09-C540-480B-A1C9-B799062F92B6/0/IOU_August_2009_RPS_Compliance_Report_Public_SCE.pdf

[20] California Public Utilities Commission, 2009. San Diego Gas & Electric August 2009 Compliance Report, http://www.cpuc.ca.gov/NR/rdonlyres/55682311-1E70-498E-AB0D-06E5F2CFBFEA/0/IOU_August_2009_RPS_Compliance_Report_Public_SDGE.pdf

[21] California Public Utilities Commission, 2010. Status of RPS Projects, http://www.cpuc.ca.gov/PUC/energy/Renewables/index.htm; Information augmented with confidential information from California Public Utilities Commission

[22] California Public Utilities Commission, 2009. Renewables Portfolio Standard. Quarterly Report Q4 2009. http://www.cpuc.ca.gov/NR/rdonlyres/52BFA25E-0D2E-48C0-950C-9C82BFEEF54C/0/FourthQuarter2009RPSLegislativeReportFINAL.pdf

[23] California Energy Commission, 2009. *An Assessment of Resource Adequacy and Resource Plans of Publicly Owned Utilities in California.* http://www.energy.ca.gov/2009publications/CEC-200-2009-019/CEC-200-2009-019.PDF

[24] California Public Utilities Commission, 2010. Utility Energy Supply Plans from 2009, http://energyalmanac.ca.gov/electricity/S-2_supply_forms_2009/

[25] California Public Utilities Commission, 2009. Confidential information for 2010 RPS compliance reports for Electric Service Providers.

[26] California Public Utilities Commission, 2010. March 2010 RPS Compliance Reports for Bear Valley Electric Utilities, Mountain Utilities, Pacificorps, and Sierra Pacific Power Company.

[27] California Air Resources Board Staff surveyed POUs to obtain the names of out-of-state renewable projects and the annual GWh generated. The following individuals with each POU provided e-mail responses to Luis Leyva:

- E. Krause, City of Anaheim
- R. Maxwell, Burbank Water and Power
- V. Puffer, Glendale Water & Power
- T. Aung, Los Angeles Department of Water & Power
- G. Stillwagon, Modesto Irrigation District
- S. Endo, Pasadena Water and Power Department
- J. Takehara, City of Roseville
- J. Roukema, Silicon Valley Power
- T. Tutt, Sacramento Municipal Utility District
- D. Severson, Turlock Irrigation District

By phone call to Luis Leyva, the City of Riverside Public Utilities Department and Imperial Irrigation District indicated their agencies have no out-of-state renewable generation.

[28] California Public Utilities Commission, 2009. CPUC 33% RPS Implementation Analysis Calculator, http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm

[29] California Public Utilities Commission, 2009. 33% Renewable Portfolio Standard Implementation Analysis Preliminary Results, http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf

[30] Renewable Energy Transmission Initiative, 2009. RETI Phase 1B Final Report, http://www.energy.ca.gov/2008publications/RETI-1000-2008-003/RETI-1000-2008-003-F.PDF

[31] California Public Utilities Commission (Prepared by Aspen Environmental), 2009. Scoring of Renewable Projects for Siting Risk and Environmental Issues, http://www.cpuc.ca.gov/NR/rdonlyres/84257CC3-2EA5-422E-90FC-3D9EE485AE1B/0/WhitePaperEnv_Scoring.pdf

[32] Air Resources Board, California Independent System Operator, California Energy Commission, and California Public Utilities Commission, 2009. Load-Modifier Assumptions, http://www.energy.ca.gov/reti/steering/2010-01-19_meeting/documents/04-Load-modifier_Assumptions_for_33-Percent_RPS_Planning_2010-01-14.pdf

[33] California Independent System Operator, 2009. *Renewable Resources and the California Electric Power Industry: System Operations, Wholesale Markets and Grid Planning* http://www.caiso.com/23f1/23f19422741b0.pdf

[34] California Independent System Operator, 2007. Integration of Renewable Resources. http://www.caiso.com/1ca5/1ca5a7a026270.pdf

[35]Chin Grant. ARB. "Re: Phone Call to discuss how LADWP shapes and firms generation from variable generation." Phone call with J. Hormozi, B. Packer, and L. Kowal, LADWP. May 5, 2010.

This Page Intentionally Left Blank

VI. RENEWABLE ENERGY CREDITS (RECS)

This chapter provides an overview of RECs and their role in renewable programs. In addition, this chapter will include a description of the CPUC's tradable REC (TREC) Decision and provide an update on the Decision.

A. Description of RECs

Chapter V provided a detailed description of renewable energy resources. RECs represent the renewable and environmental attributes of one megawatt hour (MWh) of electricity generated by an RPS-eligible renewable energy resource. The eligibility rules for renewable energy resources and the market rules for using RECs under the RES will be similar to the requirements for the RPS, with some exceptions. The differences are discussed in Chapter VII, Regulatory Design Assessment.

1. Definition of a REC

Electricity generated from an RPS-eligible facility has renewable and environmental attribute components. An example of an environmental attribute is the reduction in GHG emissions that occur when renewable power displaces fossil fuel generation. In addition, the electricity has an energy component that represents the real time physical electrical energy. RECs are used verify and track the creation and use of renewable electricity and are widely used in the United States for both voluntary green claims and compliance with state renewables programs. In California, each REC represents one MWh of renewable energy that was generated by an RPS-eligible facility. Although the electrical energy from a plant must be typically consumed at the time it is generated, RECs allow the credit for the environmental attributes of renewable power to be preserved over time.

Contracts for RECs can include the delivery of the associated electricity or can specify that the RECs are being purchased separately from the electricity. When RECs are purchased without the associated electricity, they are referred to as unbundled RECs. Similarly, a transaction where both the REC and the associated renewable energy are sold together is known as a bundled REC. Historically, RECs procured under the existing California RPS program have been bundled RECs. The CPUC Decision Authorizing Use of Renewable Energy Credits for Compliance with the California Renewables Portfolio Standard[a] (Decision) provided clarity on how unbundled RECs can be used for RPS compliance by the entities subject to CPUC jurisdiction.[1] However, on May 6, 2010, this Decision was stayed.[2] More information on the CPUC Decision is included later in this chapter.

[a] Cal. P.U.C., Decision 10-03-021 (March 16, 2010).

2. CEC's Eligible Renewable Energy Resource Requirements

As introduced in Chapter IV, to create an eligible REC for use in the California RPS program, a facility must generate renewable energy within the WECC and demonstrate that it meets the eligibility criteria of a renewable energy facility set forth in the CEC's Renewables Portfolio Standard Eligibility Guidebook.[3] The Guidebook defines the renewable resources or fuel that a facility can use and other program restrictions (such as size, online date, environmental provisions, etc.) that must be met.

A facility that has been certified by the CEC is known as an eligible renewable energy resource (also know as an RPS-eligible facility). New facilities that want their renewable energy to qualify for RPS compliance are required to be certified by the CEC under the eligibility criteria.

Facilities that have their first point of interconnection to the WECC transmission system outside the state must meet additional requirements. These facilities must be connected to the WECC transmission system and generally must have began operating after January 1, 2005 (operation can occur earlier if specific criteria are met). They must also not cause or contribute to any violation of a California environmental quality standard or other applicable requirements within California, such as an ambient air quality standard. If located outside the United States, the facility must be developed and operated in a manner that is as protective of the environment as would a similar facility located in California.

As of April 2010, CEC has certified over 600 facilities as RPS-eligible.[4] A list of current RPS-eligible generators can be found at CEC's RPS webpage.[b]

The Guidebook also contains a "delivery" requirement that affects out-of-state facilities. This provision requires that the energy produced by the certified renewable facility, or an equivalent amount of energy produced by any other facility within the same calendar year, be delivered to the California grid before the generation can count towards RPS. This requirement is discussed in the next subsection.

3. CEC Delivery Requirements

CEC rules also require that before a REC can be counted for compliance with the RPS, it must be proven that a similar amount of energy was delivered to California. Renewable energy generated within California or directly delivered to an in-state market hub, is deemed delivered.

For RECs generated from RPS-eligible out-of-state facilities to be eligible for use toward the RPS requirements, it must be demonstrated that one MWh of electricity for each REC was actually delivered to California within the same calendar year that the associated REC was generated. The delivered electricity associated with the REC generated by an out-of-state facility may come from anywhere within the WECC from

[b] http://www.energy.ca.gov/portfolio/documents/list_RPS_certified.html

any type of generating facility. Proof of the delivery within the same annual period must be provided to the CEC. The CEC compares the amount of renewable energy generated with the amount of energy delivered into California during the same calendar year and the lesser of the two amounts is counted as delivered and, therefore, RPS eligible.

4. Creating a REC

To create a REC, an eligible renewable energy resource must first register with WREGIS as an account holder and register its generating unit(s) that will be creating the renewable energy. WREGIS is an accounting system designed to issue, register, and track renewable energy generation from all geographic areas connected to the WECC.[5] On-going operation of WREGIS is funded by user fees. Users must register and pay an annual fee based on size and/or usage type, and transaction fees based on the volume of RECs in the transaction.

When an eligible renewable energy resource generates electricity, data are electronically uploaded to WREGIS by a qualified reporting authority. These data includes the month and year of the generation, monthly accumulated MWhs for each meter, the generating unit identification, and the associated meter identification(s) for each resource. WREGIS tracks each REC by a unique identification number and maintains pertinent information including the source generating the energy, the type of resource or technology that was used, and the period of generation.

As RECs are created and verified, they are placed into a WREGIS active subaccount from which they can be traded, transferred, exported, retired, or reserved. When RECs are placed in a retirement subaccount by the account holder, they are removed from circulation and can no longer be transferred or exported. Each entity subject to the RPS must maintain retirement subaccounts that they use to demonstrate RPS compliance to the CPUC. As of April 2010, there were 330 account holders in WREGIS.[6] Listed below are examples of account holders.

- Generating Unit Aggregators
- Investor Owned Utilities
- Municipal Utilities
- Rural Electric Companies
- Irrigation Districts
- Electric Service Providers
- Joint Power Providers
- Retail/wholesale Marketers
- Brokers
- Public Interest Organizations

In 2009, there were over 35,000,000 active WREGIS certificates generated that are certified for use in California, over 14,000,000 WREGIS certificates that were in a California transferred account, 124,000+ WREGIS certificates in a California reserve

subaccount, and 131,000+ WREGIS certificates that were in California retirement subaccounts.[7] It should be noted that credits certified for California may also be certified for use in another state. The large number of California-certified WREGIS certificates that have not been retired for RPS compliance is, in large part, due to the fact that utilities are anticipating additional guidance from the CEC. This guidance is expected to include how to retire the RECs, how to label the retirement-subaccount, and how to create and send a report on retired RECs to comply with RPS requirements. It is anticipated that the updated CEC guidance will be completed in the fall of 2010. It is also expected that a significant number of these California-certified certificates will be used for California RPS compliance.

5. The Role of RECs

RECs provide the essential administrative mechanism to track creation, transfer, banking and eventual retirement (for example, when they are used for compliance purposes) of the environmental attributes of renewable electricity. This mechanism allows RECs to be used to determine who has acquired the legal right to claim the renewable and environmental attributes of eligible renewable energy generation.

In the RPS program, the quantity of acquired and retired RECs is compared to a utility's quantity of retail sales, and this comparison determines if the RPS goals have been met. (Note that there are flexible compliance rules in determining compliance. See the RPS requirements for more information.) While RECs may not be double counted, RECs retired for California RPS compliance may also be used to demonstrate compliance with the RES requirements.

In addition to the use of RECs for compliance, RECs are also used in the voluntary market. This market consists of institutions, companies, organizations, and individuals that purchase RECs to demonstrate environmental stewardship. In 2008, approximately half of all RECs produced in the U.S. were sold into the voluntary market (23,000 MWh for compliance versus 24,000 MWh for the voluntary market).[8]

The specific role of RECs in the RES program is discussed in Chapter VII.

6. Cost of RECs

The renewables compliance markets in the WECC are primarily dominated by transactions for bundled products, and so there is little data available on unbundled REC trades in the West for renewables program compliance. In addition, renewables contract prices are considered confidential information. Staff consulted with REC brokers and learned that RECs sold for compliance that would be eligible for the California market have ranged from $10 to $40.[9,10] As an example, the renewable premium for RECs generated by the El Nido biomass power facility in Fresno, California was sold by Phelps Dodge Energy Services, LLC at a price of $24 per MWh. The RECs were sold for use in Arizona to both the Morenci Water & Electric District and the Ajo Improvement Company.[11,12]

The prices for RECs sold outside of the WECC vary greatly. Some RECs have sold near the alternative compliance payments levels of $50 to $55 per MWh, while others have sold in the $3 to $5 per MWh range. Alternative compliance payments are payments made to a regulatory agency by utilities in states that accept payments either in lieu of a meeting an renewables target or as a penalty for not acquiring enough renewable energy in relation to their renewables standards.

REC prices for voluntary markets are priced less than the cost of RECs used to comply with mandated renewables goals. In 2008, the cost of RECs nationally ranged from $1.50 to $5.50 per MWh. In the first half of 2009, prices dropped to $1 to $2 per MWh.[c] It should be noted that the price of a REC is highly variable due to when it was purchased, the reason it was sold and purchased, and where it is ultimately claimed for compliance.

B. CPUC's Decision on Tradable RECs (TRECs)

This section provides a description of how TRECs were defined, the CPUC's Decision authorizing the use of RECs for compliance with the RPS, and the status of the CPUCs process of incorporating TRECs into the 20 percent RPS program.

1. CPUC's Definition of a Tradable REC (TREC)

Senate Bill (SB) 107 (Simitian), Stats. 2006, ch. 464 gave the CPUC express authority to use unbundled RECs or TRECs for RPS compliance.[13] The ability to use TRECs was not fully allowed until March 16, 2010 when the CPUC approved the Decision Authorizing the Use of Renewable Energy Credits for Compliance with the California Renewables Portfolio Standard (Decision) which authorized, for the first time, the use of RECs for RPS compliance (termed tradable RECs or TRECs). A complete history of including TRECs can be found in the CPUC Decision. However, on May 6, 2010, the CPUC stayed the TREC Decision. The following discussion describes the March 16, 2010, TREC Decision.

In the CPUC Decision, TRECs were defined as an energy transaction that transfers only the environmental attributes, the REC, and not also the energy, or transfers both RECs and energy but does not meet the CPUC's criteria for a bundled transaction.

In the Decision, the CPUC defined bundled transactions as only those transactions where the renewable energy generator's first point of connection is with a California balancing authority or a transaction where the renewable energy is dynamically transferred to a California balancing authority area. Dynamic transfers include dynamic scheduling and pseudo ties.[d] Transactions that utilize dynamic transfer were

[c] Green Power Marketing in the United States: A Status Report (2008 Data).

[d] Dynamic scheduling allows the host balancing authority that receives the output from the renewable energy facility to adjust the schedule and dispatch from that facility. A pseudo tie effectively transfers the generator electrically to the receiving balancing authority allowing the balancing authority to control

considered electrically equivalent to bundled transactions interconnected to a California balancing authority area since the energy can be scheduled into California without an intermediary remarketing transaction. The CPUC also ordered staff to assess whether transactions using firm transmission should count as bundled.

Under the CPUC Decision, most existing contracts for out-of-state generation, including those where both the energy and the REC are procured concurrently, would be considered a TREC transaction (unless there is a dynamic transfer). Pursuant to statute, TREC transactions that transfer only the RECs must still demonstrate delivery pursuant to CEC rules. A TREC is also created when a REC-only transaction takes place regarding renewable generation by a California facility.

2. The RPS Program and TRECs

As stated above, the Decision authorized the procurement and trading of RECs for all regulated parties and established a few REC compliance rules. For example, the CPUC decided that all market players could participate in the REC trading market, that RECs could be traded for up to three compliance years, and consistent with RPS rules for bundled RECs, they can be banked indefinitely. For the three largest IOUs (PG&E, SCE, and SDG&E), the Decision temporarily limited the quantity of unbundled TRECs to 25 percent of their annual procurement targets and placed a $50 per MWh price cap on these unbundled transactions. The limits were to terminate on December 31, 2011, unless the CPUC acted to extend or modify the Decision prior to its expiration. For the small utilities, the CPUC included no limits on the quantity of TRECs that could be used for compliance or the price paid for the RECs. The CEC delivery requirement was not (and could not be) changed by the Decision, so the use of TRECs within the RPS is still contingent on a demonstration that an equal amount of energy was delivered to California within the same calendar year.

The Decision restricted allowable TRECs to those RECs that were generated after January 1, 2008. There were also additional requirements associated with TRECs. See the CPUC Decision for a complete list of the requirements, the associated report and the actual Decision order. A discussion on the status of the TREC Decision follows.

3. Status of the TREC Decision

On April 12, 2010, Southern California Edison and San Diego Gas & Electric companies filed a Joint Motion to Stay the TRECs Decision. In addition, these utilities plus Pacific Gas and Electric filed a Joint Petition for Modification of the Decision. On April 15, 2010, a second Petition was filed by the Independent Energy Producers Association.

On April 14, 2010, the CPUC released the *Assigned Commissioner's Ruling Setting Schedule for Consideration of Joint Petition for Modification of Decision 10-03-021 and*

---

scheduling, balancing, and outage coordination and other activities normally associated with control area services. Currently the CAISO does not use dynamic scheduling for intermittent sources, such as wind and solar resources, but is studying how to implement it.

Joint Motion for Stay of Decision 10-03-021.[14] The schedule includes a date of May 25, 2010, for a proposed decision on the petitions for modification of the Decision and a date of June 24, 2010, for the Commission's consideration of the proposed decision on the petitions for modification.

On May 6, 2010, the CPUC stayed the Decision. Modifications to the TREC decision are expected either prior to or during the comment period on the RES program.

REFERENCES

[1] California Public Utilities Commission, 2010. Decision Authorizing the use of Renewable Energy Credits for Compliance with the California Renewables Portfolio Standard
http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/115056.htm

[2] California Public Utilities Commission, 2010. Decision Staying Decision 10-03-021 and Implementing Temporary Moratorium on Commission Approval of Certain Contracts
http://docs.cpuc.ca.gov/WORD_PDF/AGENDA_DECISION/117375.PDF

[3] California Energy Commission, 2008. Renewables Portfolio Standard Eligibility, Third Edition,
http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF

[4] California Energy Commission, 2010. California's Renewables Portfolio Standard (RPS) Eligible Facilities,
http://www.energy.ca.gov/portfolio/documents/list_RPS_certified.html

[5] Western Renewable Energy Generation Information System, 2009. Frequently Asked Questions, http://www.wregis.org/faq.php

[6] Western Renewable Energy Generation Information System. WREGIS Active Account Holders, https://portal1.wregis.org/myModule/rpt/myrpt.asp?r=1&TabName=Generator

[7] Western Renewable Energy Generation Information System, 2009. Number of certificates by State/Provincial/Voluntary Program Eligibilities,
https://portal1.wregis.org/myModule/rpt/myrpt.asp?r=108&TabName=SPV

[8] National Renewable Energy Laboratory, 2009. Green Power Marketing In the United States A Status report (2008,Data),
http://www.nrel.gov/docs/fy09osti/46581.pdf

[9] Arnold, Greg. CE2 Capital Partners. "Re: contact Information" Email to Christopher Gallenstein. April, 2010.

[10] McGowan, Ian. 3Degrees, Inc. "REC $ ranges" Email to Christopher Gallenstein. April, 2010.

[11] Arizona Corporation Commission (Attached document Prepared by Ajo Improvement Company), 2009. Renewable Energy Standard and Tariff Compliance Report 2008 Compliance Year,
http://images.edocket.azcc.gov/docketpdf/0000095139.pdf

[12] Arizona Corporation Commission (Attached document Prepared by Morenci Water and Electric), 2009. Renewable Energy Standard and Tariff Compliance Report 2008 Compliance Year, http://images.edocket.azcc.gov/docketpdf/0000095138.pdf

[13] California Legislature, 2006. Senate Bill 107, http://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_0101-0150/sb_107_bill_20060926_chaptered.pdf

[14] California Public Utilities Commission, 2010. Assigned Commissioner's Ruling Setting Schedule for Consideration of Joint Petition for Modification of Decision 10-03-021 and Joint Motion for Stay of Decision 10-03-021. http://docs.cpuc.ca.gov/efile/RULINGS/116324.pdf

This Page Intentionally Left Blank

VII. REGULATORY DESIGN ASSESSMENT

California's existing RPS program was used as a foundation for developing the proposed RES regulation. To the greatest extent possible, the proposed regulation utilizes the structure, provisions, policies, and implementation mechanisms that the CEC and CPUC established for the RPS program. The proposed RES does not replace or displace any obligation retail sellers of electricity have under the existing RPS program. Both the RPS and the proposed RES will be implemented concurrently.

This chapter provides a brief description of how the RES regulatory approach compares to the current RPS program and summarizes the analyses used to support specific design elements of the proposed regulation. These analyses provide ARB staff's rationale for using existing RPS program requirements as the primary structure for the proposed RES regulation, as well as justification for any alternative provisions. The specific provisions in the proposed RES Regulation are described in the next chapter (Summary of the Proposed Regulation).

A. Comparison of the RPS program to the Proposed RES

Retail sellers of electricity that are regulated by the CPUC (IOUs, ESPs, and CCAs) are obligated to meet the 20 percent renewable energy requirement under the RPS. POUs and electrical cooperatives can set their own targets and compliance dates. Under the proposed RES, POUs and the electrical cooperatives will be subject to the same renewable energy percentages and compliance dates as the IOUs, ESPs, and CCAs. Retail sellers are still obligated to satisfy their RPS requirements, and the CEC and CPUC will continue the same administrative roles for implementing and enforcing retail seller's obligations under the RPS. The California Department of Water Resources (DWR) and Western Area Power Administration (WAPA) are not subject to the RPS but will be required to report annually to the ARB under the proposed RES.
CEC will still be responsible for certifying eligible resources according to CEC's eligibility guidelines. Renewable energy resources that are eligible for the RPS will also be eligible for the proposed RES. One exception will be POU resources that are not eligible for CEC certification but have been claimed by POUs for meeting RPS requirements. Specific provisions for these types of resources are included in the proposed regulation and are discussed later in this chapter.

RECs will continue to be the accounting tool to demonstrate procurement of renewable energy under the RES. However, unlike the RPS program, RECs generated from an out-of-state generator do not require an equivalent amount of energy to be delivered to California under the RES. Also, RECs can be traded or banked to meet a regulated party's renewable energy standards.

Both programs use a compliance metric based on megawatt-hours (MWh). ARB staff is developing the proposed RES under the AB 32 authority, as it is a GHG reduction measure. ARB staff conducted an assessment to determine whether the MWh metric in the RPS would produce equivalent GHG emission reductions as a requirement based

on a mass or percent GHG emission reduction requirement. Staff's analysis concluded that the net GHG benefit provided by displacing one MWh of power from the grid with renewable energy is similar across most renewable technologies, with the exception of combusting landfill or digester gas in an engine (see discussion of analysis in Appendix C). Therefore, the use of a MWh metric for requiring California's retail sellers of electricity to provide 33 percent of their retail sales from renewable energy resources is expected to produce comparable GHG emissions reductions to a standard based on a mass or percent GHG emission reduction requirement.

The primary areas where the proposed RES is similar to the RPS program are listed below:

- The definition of eligible renewable facilities or resources.
- Certification procedures and requirements for eligible facilities.
- Using RECs as the accounting tool.
- Measuring compliance based on megawatt-hours (MWh).

The areas where the proposed RES diverges from the RPS program are identified and explained further in the next section.

B. Primary Areas Where the Proposed RES Diverges from the RPS Program

The primary areas where the proposed RES regulation diverges from the RPS program are as follows:

- Holding the POUs, and electrical cooperatives, to the same compliance obligations and dates as the IOUs, ESPs, and CCAs.
- Requiring DWR and WAPA to report electricity generation and sales to ARB annually.
- Providing a partial exemption threshold for California's smallest retail sellers of electricity.
- Allowing non RPS-eligible POU resources (designated in the RES regulation as "RES Qualifying POU Resources") to be used toward RES compliance. These types of resources, primarily large hydroelectric power plants greater than 30 MW, are not eligible for CEC certification, but have been claimed by some POUs toward their RPS obligation. The amount of allowable generation from these resources is capped at an amount that is equal to 20 percent of renewable energy procurement and the allowance ends when the contracts for these renewable resources expire.
- Establishing interim standards.
- Providing more flexible REC options for compliance (allowing unlimited trading of RECs and no delivery requirements for out-of-state generation) to maximize GHG reductions, minimize compliance cost, and increase the potential availability of renewable resources.
- Establishing ARB as the enforcement entity and modifying the penalty provisions for noncompliance.

These points are discussed in more detail below.

1. POU and Electrical Cooperative Obligations

Executive Order S-21-09 directed ARB to include all California retail sellers of electricity when developing the RES program. Consequently, under the proposed RES, POUs and the electrical cooperatives will be subject to the same renewable energy percentages and compliance dates as the IOUs, ESPs, and CCAs.

2. DWR and WAPA

ARB staff also considered DWR and WAPA when developing the proposed RES. DWR and WAPA play important roles in providing water and electricity to California. A description of DWR and WAPA responsibilities and operations were included in Chapter III. Under the proposed RES, these regulated parties will be required to annually report on their electrical operations. This information will be used by ARB to determine if future modifications are needed to the RES requirements affecting DWR and WAPA.

3. Partial Exemption Threshold for Regulated Entities

ARB staff received numerous comments supporting the idea of an exemption threshold to relieve some utilities from having to comply with a renewable energy standard. As such, ARB staff conducted an analysis to determine an appropriate threshold level.

ARB staff began by looking at the impact various threshold levels would have on the percentage of California's retail electricity sales market that would be subject to the regulation. ARB staff obtained recent sales data from the CEC and CPUC for each retail seller. Based on this information, ARB staff estimated the percent of the market that would be impacted by the 500 GWh, 200 GWh, and 100 GWh thresholds. These levels were suggested by CEC, CPUC and ARB staff as possible exemption thresholds for examination.

Sales data indicated that approximately 99.7 percent of retail sales would be subject to the RES if a 100 GWh threshold was used, 99 percent of retail sales would be subject with a 200 GWh threshold, and 98 percent of retail sales would be subject with a 500 GWh threshold.

ARB staff conducted a telephone survey of retail sellers to determine the economic impact of complying with the proposed regulation. (See Appendix C for the survey.) In order to establish a proposed threshold, staff surveyed ESPs, IOUs, and POUs of various sizes (75 to 1,200 GWh) to determine current costs and various factors that affect future electricity costs under the proposed RES. Staff calculated the retail sellers' regulatory compliance cost from the retailers' responses and the averaged retail sales and eligible renewable portion of sales for each.[1,2,3,4] Retail electric sales and the renewable portions were averaged for 2007 – 2009 calendar years for each entity. For

this analysis, estimated regulatory costs included the purchase cost of RECs as well as other costs associated with administering each retail seller's regulatory compliance.

Regulatory Cost = REC purchase cost + Administrative cost

REC purchase cost = [Retail Electric Sales (MWh) – Current Eligible Renewables (MWh)] x REC cost ($50/MWh)[a]

Administrative costs consist of the costs associated with locating and procuring RECs and preparing the necessary reports to ARB on an annual basis. Staff contacted 19 retail sellers and received feedback from 12 of them regarding their administrative cost estimates.[5] The surveyed retail sellers determined costs by estimating consulting fees and any additional personnel resources that each retail seller deemed necessary to meet its RES obligation if it were to be regulated. Cost estimates were based on the days/weeks/months to procure RECs, prepare and file annual reports to ARB.

Staff used the results of the survey to determine if electricity sales to retail end-use customers was a good indicator of the economic impact of complying with the proposed regulation. The information obtained from the retail sellers surveyed is confidential and is not listed. However, staff used the data from the survey to present a graphical representation of the results in Figure VII-1.

[a] See chapter VI, section B, *CPUC's Decision on Tradable RECs (TRECs)*

Figure VII-1
Retail Sellers' Cost of Compliance

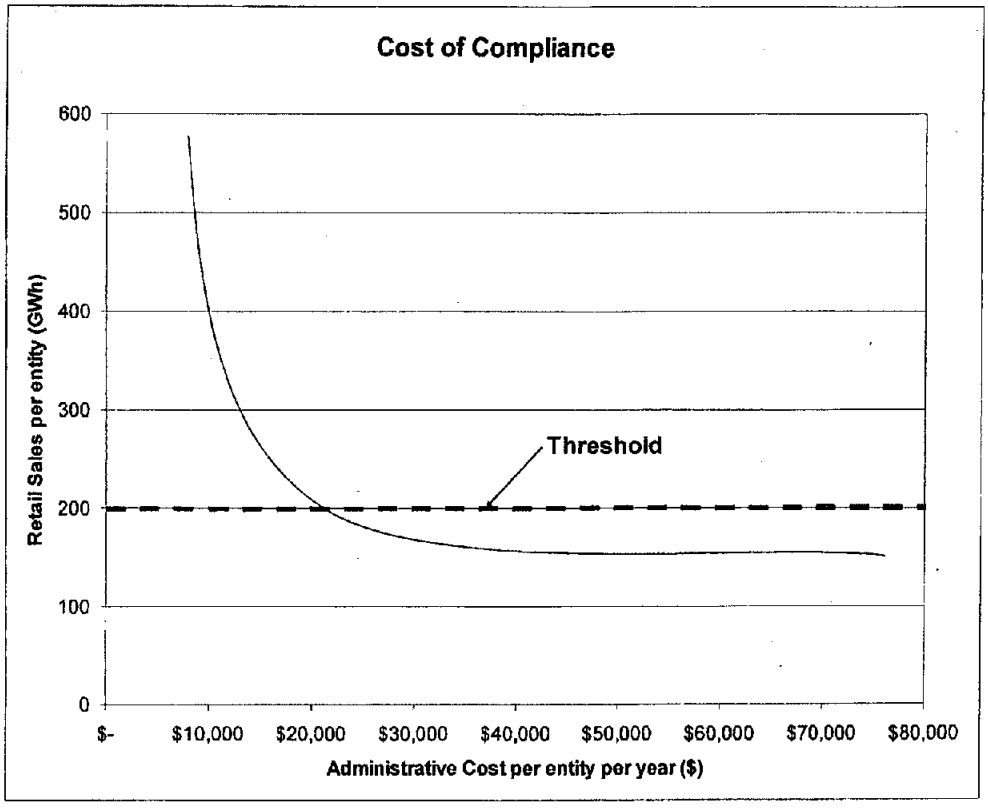


Figure VII-1 shows that the cost of compliance increases dramatically as the sales decreased below the threshold level. Also, staff determined that the entities surveyed with retail sales of 200,000 MWh or less would experience twice the administrative burden, relative to their REC costs, than retail sellers exceeding 200,000 MWh. Table VII-1 below compares the averaged administrative costs per REC purchased costs of entities above 200,000 MWh with the average of those 200,000 MWh or less.

Table VII-1
Administrative Burden

Retail Sales	Average Administrative Cost / Average REC Purchase Cost
> 200,000 MWh	1%
<= 200,000 MWh	2%

The analysis shows that retail sellers that qualify for the partial exemption are so small that they do not have the staffing or budget to absorb the administrative burden of compliance with a 33 percent renewables requirement. Requiring these entities to spend additional funds to procure renewable energy or RECs would create a disproportionate use of resources relative to the environmental benefits.

ARB staff determined that utilities that annually provide no more than 200,000 MWh of electricity to retail end-use customers, averaged over calendar years 2007 through 2009 should be exempt from the 33 percent renewables requirement. However, these entities would still be subject to reporting requirements. The three year averaging of retail sales was proposed to account for year to year variations in load served. If a utility that qualifies for partial exemption has annual sales to retail end-use customers in excess of 200,000 MWh, in calendar years 2010 and thereafter, that utility will no longer be eligible for the partial exemption and will have a renewable energy requirement.

Below is a list of entities that staff believes would be eligible for partially exemption based on the available data, in alphabetical order:

- 3Phases
- Anza Electric
- Banning
- Bear Valley Electric Services
- Cerritos
- City of Biggs
- Corona Power
- City of Gridley
- City of Healdsburg
- City of Industry
- City of Lompoc
- City of Ukiah
- Eastside Power Authority
- Hercules
- Lassen MUD
- Moreno Valley
- Mountain Utilities
- Needles
- Pittsburg (Island Energy)
- Plumas-Sierra Rural Electric
- Port of Oakland
- Port of Stockton
- Rancho Cucamonga
- Shasta Lake
- Shelter Cove Resort Improvement District
- Surprise Valley Corporation
- Trinity PUD
- Truckee Donner Public Utilities District
- Valley Electric Association
- Victorville

4. RES Qualifying POU Resources

POUs are allowed to set voluntary targets and compliance dates under the RPS. Under the proposed RES, the POUs will be obligated to meet interim compliance standards and the final 33 percent target by 2020 like all other retail sellers subject to the proposed regulation. Under the RPS program, POUs are given greater flexibility than the large IOUs in defining and procuring renewable energy resources. While most POUs rely on resources certified by the CEC as eligible for the RPS program, a number of POUs have procured "uncertified" generation resources that they include in their demonstration of electricity produced by renewable resources.

The proposed RES allows continued use of these resources towards meeting RES compliance obligations, subject to certain limitations. This approach recognizes prior utility investments in this wider set of renewable resources and maintains RPS program consistency under the transition to the RES program. In the proposed RES regulation, these uncertified resources are defined as "RES Qualifying POU Resources."

Under the proposed RES regulation, POUs may use a capped amount of generation from "uncertified" resources that are currently being claimed under the RPS program. Contractual investments to procure these resources must have occurred on or after the January 1, 2003, effective date of the RPS program, and prior to the September 15, 2009, date of Executive Order S-21-09. Uncertified generating resources owned and operated by POUs and claimed for RPS compliance prior to September 15, 2009, are eligible under the RES. The amount of eligible generation from procured investments or owned resources is capped at 20 percent of the POU's annual retail sales. Additionally, once original contractual investments in procured resources expire, affected POUs will be required to replace the resources with renewable resources otherwise eligible for the RES. Generating resources owned and operated by POUs may continue to be used for the RES without expiration.

ARB staff used information in the POUs' resource adequacy plans filed with the CEC to identify the POUs that have claimed the use of uncertified resources and the amount of generation from these resources during calendar year 2008 for meeting RPS program goals. The majority of the resources claimed are from large hydropower with a capacity greater than 30 MW (the CEC certification program sets a limit of 30 MW or less for RPS-eligible hydropower). Other generation claimed includes self generation, uncertified digester gas, uncertified aqueduct hydro, and RECs from out-of-state wind.

Table VII-2 identifies the POUs that have claimed uncertified resources for RPS (now referred to as RES Qualifying POU resources in the proposed RES) and the type of resource. The table also presents the POU's percent renewables with and without claiming these types of resources. The resources were not capped at 20 percent, as only the Power and Water Resources Pooling Authority's (PWRPA) uncertified resource generation (large hydro) exceeded 20 percent of its 2008 retail sales.

Table VII-2
"Uncertified" Resources Claimed as Renewable Generation by POUs in 2008

POU	Generation Type	2008 Generation of RES POU Qualifying Resources (GWh)	Percent Renewable w/out RES POU Qualifying Resources[1]	Percent Renewable w/ RES POU Qualifying Resources
City & County of San Francisco	Self-Generation	6	0	100[2]
City & County of San Francisco	Large Hydro	1,287		
Los Angeles Department of Water & Power (LADWP)	Digester gas	154	5	7
Los Angeles Department of Water & Power (LADWP)	Aqueduct hydro	434		
Northern California Power Association (NCPA)[3]	Large Hydro	333	23	38
City of Palo Alto[4]	RECs	57		
Power & Water Resources Pooling Authority (PWRPA)	Large Hydro	174	9	29
City of Riverside	Large Hydro	34	8	9
Roseville Electric	Large Hydro	153	7	18
Sacramento Municipal Utility District (SMUD)	RECs	219	18	20
City of Vernon	Large Hydro	20	0	2
	Total	**2,872**		

(1) The values represent the POU's percent renewable using only the POU's CEC certified resources.
(2) The proposed RES allows regulated parties with large hydropower generation that is greater than 67 percent of retail sells to use all of this generation to comply with the RES standards. This provision would apply to CCSF.
(3) Ten members of the Northern California Power Agency (NCPA) collectively report resource data to CEC under the entity "NCPA.
(4) In 2008, RECs reported by the City of Palo Alto were able to be separated from NCPA's collective renewable generation, but currently there is no individual renewable portfolio for this POU. Consequently, its total renewable percentage is reported as part of NCPA.

Uncertified resources claimed by the POUs for meeting RPS goals equal approximately 2,900 GWh of generation, which accounts for four percent of total 2008 POU retail electricity sales, or less than one percent of the total 2008 retail sales of electricity from all retail sellers in California. The impact of allowing these uncertified resources to be claimed under the RES will vary by POU. To be equitable, those resources invested in by the POUs for RPS compliance should also be allowed for RES obligations. However, staff is proposing capping this generation at a level that would be equal to the renewable generation needed for meeting the 20 percent RPS targets.

5. Compliance with Interim and 33 Percent RES Standards

This section discusses staff's proposal for including interim and final compliance standards for regulated entities as they increase procurement of renewable energy from the 20 percent requirement in the RPS to the 33 percent requirement.

Prior to 2010, retail sellers obligated under the RPS program were required to increase procurement from eligible renewable energy resources annually by at least one percent of the previous year's retail sales, until they reach 20 percent renewables. Entities are allowed three years to make up any shortfalls in any year, essentially giving them until the end of 2013 to meet the 20 percent target. (See Chapter IV for more information on the flexible compliance provisions in the RPS program.) The CPUC sets annual procurement targets (APTs) for regulated entities, denoting the amount of renewable energy that the entity must procure each year for compliance with the RPS.

To provide flexibility to affected entities and to simplify compliance, staff is proposing an alternative compliance mechanism for the RES. Staff determined that a phase-in of multi-year renewable percentage targets from 2013 to 2020 would provide achievable interim benefits from the regulation and would lead to greater certainty of ultimate compliance in 2020. The following targets are proposed: 20 percent for 2012-2014, 24 percent for 2015-2017, 28 percent for 2018-2019, and 33 percent in 2020 and beyond. Entities are provided three-year compliance intervals in the early years of the RES program to allow more flexibility with procuring additional renewable energy. Compliance year intervals are reduced to two years in the 2018 to 2019 period before becoming annual requirements in 2020 and beyond.

To determine if the proposed interim standards were reasonable targets to set for demonstrating progress toward meeting the 33 percent goal, staff had to evaluate if affected LSEs could potentially meet them. Staff had to first determine which LSEs would potentially be affected by the regulation and then evaluate renewable energy procurement data for those entities.

a. Available Data

Staff's analysis for meeting interim standards addressed only retail sellers that provided over 200 GWh of annual retail sales averaged over calendar years 2007 through 2009. As discussed earlier in this chapter, staff is proposing an exemption threshold of 200 GWh of total retail sales averaged over calendar years 2007 through 2009. The only entities exceeding this threshold that had available data for this analysis were the POUs and IOUs.

(1) Publicly Owned Utilities (POUs)

ARB staff used information contained in 19 POU resource adequacy plans filed with the CEC to estimate the ability of POUs to meet the proposed RES interim compliance standards. The plans include renewable generation that the POUs own and operate

and include approved renewable energy contracts. Most of the plans included renewable forecasts through 2018 but not through 2020. In those cases, staff increased the retail sales by 1.2 percent per year in accordance with the latest 2009 IEPR load demand forecast to provide a uniform means of evaluating all of the POUs through 2020. For this analysis, staff also included "uncertified" large hydro previously claimed for RPS compliance. However, these resources were capped at a maximum of 20 percent of an entity's annual retail sales in accordance with the proposed RES.

The analysis of individual POUs showed a large difference in the amount of renewable energy procured to meet California retail load in their individual resource plans. The results can range from about two percent to about 54 percent renewable in the final 2020 compliance year. A primary reason for the variation is that under the RPS program, the POUs set their own renewable procurement targets. Some POUs are currently pursuing aggressive renewable portfolios under the RPS, while others are not, resulting in some POUs needed to be much more aggressive in procuring renewable energy resources to comply with the proposed RES standards.

Table VII-3 shows the aggregated results for the 19 POUs' projected retail sales and projected renewable energy for years 2012 through 2020.

Table VII-3
Projected POU Interim Compliance Summary by Year (GWh)

Compliance Year	Projected Retail Sales	Projected Renewable Energy[1]	Percent Renewable Generation Compared to Retail Sales	Proposed RES Standard[2]
2012	61,900	15,200	23	20
2013	62,500	16,400	25	20
2014	63,200	17,600	27	20
2015	64,000	18,600	28	24
2016	64,700	19,500	29	24
2017	65,200	20,000	29	24
2018	65,900	20,900	30	28
2019	66,500	21,400	31	28
2020	67,100	21,400	31	33

(1) Includes "uncertified" large hydropower generation previously claimed for RPS compliance. This generation was capped at 20 percent of the POU's annual retail sales as will be allowed in the proposed RES.

(2) Proposed RES compliance standards are actually averaged over 2012-2014, 2015-2017 and 2018-2019 compliance years and are determined on an annual basis in 2020 and beyond.

These results assume that all of the reported contracts come on-line and are operational throughout the interim compliance period. The results illustrate that as a group, the POUs are projected to meet the proposed interim compliance standards but

not the final 2020 compliance year. However, the results would not be the same on an individual basis. Seven POUs are pursuing aggressive renewable energy portfolios and are expected to have renewable energy in excess of the interim and 2020 standards. In this case, these entities will have excess RECs available for banking or trading. However, not all of the POUs are pursuing such aggressive renewable energy programs. The remaining 12 POUs evaluated as part of this analysis will need to procure additional renewable energy or purchase RECs to meet the interim compliance years standards and the 2020 standard.

(2) Investor Owned Utilities (IOUs)

To evaluate the ability of California's three largest IOUs (PG&E, SDG&E, and SCE) to satisfy the proposed interim compliance standards and the final 2020 standard of the RES, staff evaluated the progress of these three IOUs toward achieving higher renewable energy percentages for RPS compliance. This evaluation is based on the renewable contract commitments for IOUs that were in place prior to the creation of the RPS program, and the generation represented by contractual commitments made to satisfy the RPS program.

All of the three IOUs had renewable generation portfolios prior to the existence of the RPS program. The RPS program became effective in 2003—hence, contracts that existed prior to 2003 were not intended for RPS compliance. In 2010, this pre-2003 portfolio is projected to represent about nine percent of the large IOU's retail sales. Many of these long-term contracts will expire by the end of 2020. From 2013 to 2020, the three largest IOUs, collectively, will have nearly 10,000 GWh of renewable generation from contracts scheduled to expire.[6,7,8] At this time, it is unclear if the generation represented by the expiring contracts will be renewed by the IOUs or sold to other regulated parties.

For this evaluation, ARB staff included all generation being delivered to IOUs. This includes the contracts that were executed prior to RPS implementation ("Renewables in Pre-2003 Contracts") and contracts procured after this date for RPS compliance. These projects included contracts that CPUC has deemed "operational," as well as contracts referred to as "CPUC-approved" projects still in the development stage, and projects that are "pending CPUC approval."[9,10]

The total projected renewable energy generation information is summarized below in Table VII-4. The generation listed under "Renewables in Pre-2003 Contracts" represents generation procured before 2003 that is delivering electricity to the large IOUs. The generation listed under "Renewables in RPS Contracts" represents both on-line generation and projected generation that was procured for RPS compliance. As shown in this table, the generation associated with RPS contracts climbs quickly from 2013 thru 2015, reaching a peak in 2017. Thereafter, the generation associated with RPS contracts declines slightly. At the same time, renewable generation associated with pre-2003 contracts decline every year as the older contracts expire.

Table VII-4
Projected IOU Renewable Generation Based on Contracts
(GWh)

Compliance Year	Renewables in Pre-2003 Contracts	Renewables in RPS Contracts	Total Projected Renewable
2012	15,000	28,000	43,000
2013	15,000	32000	47,000
2014	14,000	38,000	52,000
2015	13,000	41,000	54,000
2016	11,000	43,000	54,000
2017	9,800	43,000	52,800
2018	8,800	42,000	50,800
2019	6,300	42,000	47,300
2020	4,700	41,000	45,700

Table VII-5 compares the amount of total projected retail sales to total projected renewable generation for the three large IOUs.

Table VII-5
Large IOU RES Compliance

Compliance Year	Total Projected Retail Sales (GWh)	Total Projected Renewables	Percent Renewable Generation Compared to Retail Sales	Proposed RES Standard
2012	180,000	43,000	24%	20
2013	184,000	47,000	26%	20
2014	186,000	52,000	28%	20
2015	188,000	54,000	29%	24
2016	191,000	54,000	28%	24
2017	193,000	53,000	28%	24
2018	196,000	50,000	26%	28
2019	198,000	48,000	24%	28
2020	201,000	46,000	23%	33

As shown in the table, renewable generation is expected to make up between 23 to 29 percent of large IOU retail sales between 2012 and 2020. As discussed earlier, the projections shown in the above table assume that the pre-2002 contracts will expired

and that all contracts in the CPUC database will be fulfilled. Based on the assumption that all contracts will be fulfilled, the large IOUs could satisfy the interim targets of the proposed regulation through 2017. Largely due to the expiration of the pre-2003 contracts, the large IOUs would be somewhat short (anywhere from one to six percent) of the 2018 to 2020 standards and would need to acquire additional renewable resources, use banked credits from previous years' over-compliance, or purchase RECs to meet these standards. If the large IOUs extend all the expiring contracts and all the RPS contracts are fulfilled, the percentage for years 2018 through 2020 would exceed 28 percent.

In summary, the table represents an optimistic forecast of the total renewable generation that may come online, but the actual implementation is likely to fall short of the presented projections. However, staff believes that any shortfalls could be replaced by either purchasing RECs or procuring new renewable generation to satisfy the new proposed RES standards. In addition, it is likely that some of the expiring contracts for pre-2002 renewable generation will be extended. As discussed in Chapter V (Technology Assessment), the RES Calculator results indicate that there is substantial renewable generation potentially available both within California and within the WECC. Thus, it is likely that additional renewable generation can be procured to meet the 2020 RES standard.

(3) Small and Multi-Jurisdictional IOU Interim Compliance Feasibility

These retail sellers consist of two multi-jurisdictional IOUs and two small IOUs. Based on the 200,000 MWh applicability threshold, the two small IOUs would not be subject to the proposed RES.[11] Consequently, only the two multi-jurisdictional IOUs are expected to be affected by the proposed RES regulation. To evaluate the ability of the multi-jurisdictional IOUs to meet the proposed RES standards, staff evaluated the information contained it the August 2009 CPUC compliance reports that were filed by these IOUs.

The compliance reports are based on renewable generation that has been procured to satisfy the RPS program. The generation is expected to be nearly constant from 2012 through 2020. Table VII-6 shows that collectively the multi-jurisdictional IOUs are not expected to meet the interim compliance standards from 2012-2020. Individually, one of the multi-jurisdictional IOUs is expected to meet the 20 percent RPS target in 2010 and the other is slightly below that level. Both of the multi-jurisdictional IOUs will have to procure additional renewable resources or purchase RECs to move from the 20 percent goals in the RPS to the 33 percent RES standard in 2020. These two multi-jurisdictional IOUs account for less than one percent of IOU retail electricity sales in California.

Table VII-6
Multi-Jurisdictional IOU RES Compliance
(GWh)

Compliance Year	Projected Retail Sales	Total Projected Renewables	Percent Renewable Generation Compared to Retail Sales	Proposed RES Standard
2012	1,440	240	17	20
2013	1,450	240	17	20
2014	1,450	240	17	20
2015	1,450	240	17	24
2016	1,450	240	17	24
2017	1,460	240	16	24
2018	1,460	240	16	28
2019	1,460	230	16	28
2020	1,460	230	16	33

b. Summary

Based on the POUs' and IOUs' current procurement activity to meet RPS obligations and the assumption that historically some RPS contracts are never fulfilled, most retail sellers will have to procure more renewable energy and/or purchase RECs to meet all of the proposed RES compliance standards. Some POUs are aggressively procuring renewable generation, which will result in these POUs being able to bank excess RECs in the early compliance years, aiding their ability to meet all of the standards. Other POUs with less aggressive procurement planning will need to procure additional resources or purchase RECs to meet the proposed standards. The large IOUs are expected to meet the proposed standards through 2017, but would be somewhat short (anywhere from one to six percent) of the 2018 to 2020 standards and would need to acquire additional renewable resources, use banked credits from previous years' over-compliance, or purchase RECs to meet these standards. Finally, the multi-jurisdictional IOUs will be the most challenged in meeting the proposed RES standards and will need to aggressively procure new renewable generation and /or purchase RECs to meet the standards.

The RES Calculator (see Chapter V for a discussion on the RES Calculator) indicates that there is substantial renewable generation potentially available both within California and within the WECC, which could be used by regulated parties to meet the proposed standards.

Staff will evaluate the regulated parties' progress toward satisfying the interim and final 2020 compliance standards as part of the regulation reviews required in the proposed RES. These reviews shall be completed and presented to the Board by December 31, 2013, December 31, 2016, and December 31, 2018.

6. Treatment of RECs in RES

As with the RPS program, RECs are proposed as the compliance mechanism for the RES. Whether to allow only bundled or unbundled RECs, with or without delivery requirements, was one of the most important considerations in the RES regulatory design. As discussed in Chapter VI, until recently, the RPS program allowed only bundled RECs with an equivalent amount of power required to be delivered to California for out-of-state generators. The recent CPUC Decision allowed a limited amount of tradable RECs for meeting RPS compliance. The delivery requirement for out-of-state generation was still required under the Decision. On May 6, 2010, the CPUC Decision was stayed pending further evaluation by the CPUC. However, under the stayed CPUC's Decision and under the CEC delivery requirements, RECs were restricted in their ability to be used for RPS compliance for the three largest utilities.

The RES regulation does not change any requirement that a regulated party must meet under their RPS obligation but it does allow all regulated parties to acquire an unlimited amount of unbundled RECs without the energy having to be delivered toward satisfying the RES renewable energy percentage requirements. The regulation will not allow earmarking of RECs. Earmarking is a term which describes applying RECs that have not yet been generated to a current RPS shortfall. The proposed regulation will also not include a price cap on RECs but the CPUC has the authority to regulate utility rates and adopt any cost containment rules that are reasonable.

Staff evaluated the pros and cons for several options relative to conditions under which RECs could be created and used for RES compliance. These included:

- Requiring or not requiring energy delivery to California;
- Allowing or not allowing renewable energy and corresponding RECs to be sold separately; or
- Limiting or not limiting the amount of unbundled RECs that could be used for compliance.

ARB staff concluded that there are benefits to allowing maximum flexibility with respect to REC acquisition. These benefits include:

- Increasing the certainty that the interim and 2020 targets will be met;
- Allowing more compliance options to deal with year-to-year variations;
- Helping smaller POUs and others to comply; and
- Maintaining GHG benefits in a less costly manner.

Staff also recognized the disadvantages to allowing maximum flexibility in regards to RECs. As discussed in Chapter V, staff used the RES Calculator to determine potential renewable energy portfolios under various scenarios. Based on the RES Calculator output, there was a less than one percent loss of criteria pollutant reduction when renewable energy was not limited to in-state projects. However, the in-state only REC scenario resulted in an economic increase with no additional GHG reductions. See Chapters IX, X and XI for more information on the Environmental and Economic

Impacts, and the in-state generation only regulatory alternative. Staff believes that overall, the benefits of allowing an uncapped amount of unbundled RECs without the power delivery requirement are greater than the disadvantages of not allowing them.

A discussion of the role of RECs in the RES program as well as a discussion on REC property rights and necessary changes to WREGIS follows.

a. REC Documentation Using WREGIS Certificates

As noted above, RECs represent the environmental attributes of electricity generated from a renewable resource. The criteria distinguishing a resource as a renewable resource are generally defined by law. A resource considered as a renewable resource in one state (or program) may not be considered as a renewable resource in another state (or program). Thus, what may be recognized as a REC in one state (or program) may not be recognized as a REC in another state (or program). In California, the RES would allow RECs without the associated delivery of electricity. Under the existing RPS, these RECs would not be eligible.

Although the term "REC" is used as a generic description of the environmental attributes of renewable generation, the term as used in the RES regulation has a specific meaning. ARB has created unique parameters for eligibility. What is to be considered as 'renewable' is a matter of law, and before generation can be considered as eligible to produce a REC for RES purposes, it must meet specific requirements unique to that program. The RES regulation defines what generation is acceptable for use in meeting its requirements, and does not attempt to define or limit the uses of generation from resources for any other reason or purpose.

To determine compliance with RES requirements, ARB will rely on certificates issued by WREGIS. Only WREGIS certificates representing RECs from eligible resources will be accepted. Such qualifying certificates will be the only means for documenting eligible RECs and RES compliance. Although WREGIS issues certificates for RECs covering all types of renewable generation, ARB has identified only a certain subset that qualifies to meet RES requirements. The regulation's focus is on the WREGIS certificate, not what the WREGIS certificate represents. By convenience, ARB will rely on this existing infrastructure; however, ARB is using this existing system in a unique way, which is solely as a means of documenting compliance. Similar to allowance trading programs, then, ARB has created a compliance accounting tool solely defined by, and for use within, the regulatory program. Therefore, no property right has been created by their recognition in the proposed regulation. Nothing in this proposed regulation is intended to affect RECs in general or how RECs may be otherwise used or traded to meet requirements outside the RES regulation.

b. REC Banking and Trading

The RES regulation proposes to limit REC trading to a period of three calendar years from the date the associated WREGIS certificate is issued or until a REC has been

placed in a WREGIS retirement-subaccount, which ever occurs first. WREGIS certificates associated with RECs can be retained in an active-subaccount for no more than three calendar years inclusive of the year in which the certificate was generated.

Prior to the end of the three year period, a WREGIS certificate must be moved to a retirement-subaccount in order to be counted towards RES compliance. Once they are placed in the WREGIS retirement-subaccount, WREGIS certificates not used to meet a compliance interval obligation remain bankable without a time limit to be used by the account holder to meet future RES obligations. The CPUC believes, and ARB staff agrees, that limiting the trading of RECs to three years strikes an appropriate balance between maintaining market flexibility, increasing liquidity, and discouraging hoarding of RECs.[12]

The RES proposal would allow RECs to be procured by any party. Trading could take place between generators, regulated parties, brokers, and wholesale marketers of RECs. However, retail electricity sellers subject to the partial exemption in the RES regulation (those with retail sales of less than 200 GWh) and RES Qualifying POU Resources (as described earlier in this chapter) could not use owned or procured generation to create RECs that could be transferred to other parties. To preserve the environmental benefits of renewable generation by a retail seller that have been partially exempted from the regulation or have created RECs from RES Qualifying POU Resource, staff is proposing to prohibit selling any RECs that they have procured under these circumstances. In addition, for the retail sellers subject to the partial exemption in the RES regulation, no REC banking will be allowed for purposes of the RES regulation. WREGIS certificates associated with RECs for RES Qualifying POU Resources can be retired in WREGIS and banked for later use in the RES by the POU that owned the REC originally.

The Green Power Network provides information about wholesale and retail renewable energy certificate marketers and brokers throughout the United States. The network website lists 25 active REC marketers, 17 REC Brokers/Exchanges, and 86 Active Commercial and/or Wholesale Marketers.[13] WREGIS currently has approximately 36 registered brokers and wholesale marketers. It is expected that some of the RECs generated by RPS-eligible facilities will be purchased and traded by these brokers and marketers. ARB staff will be monitoring REC trading and will perform an assessment of such trading as part of the regulation review in 2013.

c. Regulated Parties' Procurement Contracts and RECs

As shown earlier in this section, if the regulated party's contracts and associated transmission expansions come to fruition, the interim standards are expected to be achievable, at least for California generation as a whole. In addition where a regulated party acquires renewable generation in excess of the RECs requirement for any given compliance period, the proposal would allow the excess RECs to be banked and used for later compliance period or to be traded to other entities. Those regulated parties that are capable of over-complying in the early years can bank RECs for later use. Regulated parties that have acquired sufficient renewable generation to over-comply

with interim requirements and have sufficient contracts for compliance in the latter years will be able to trade some of their excess RECs subject to the restriction previously mentioned.

Based upon the signed contracts for both the POUs and the IOUs, as shown above in Table VII-3 and Table VII-5, there will be excess RECs available. As a best case, if all the contracted generation that has been procured comes to fruition, the POUs may have in excess of 27,000 GWhs by 2020. The IOUs similarly may have approximately 23,000 GWhs of RECs by 2020. However, staff believes that not all facilities or the associated transmission will be built following the schedules for deployment. In addition, as the renewable energy standards are met by the regulated parties in California and in the WECC, fewer new renewable generation facilities are expected to be built, resulting in a limit to the quantity of RECs available for trading. The next section discusses RECs in the WECC.

d. Other State RPS programs and RECs in the WECC

There are currently eight states within the WECC that have RPS programs. However, the REC definitions, nomenclature, and requirements are not consistent across these states. (See Table IV-1 in Chapter IV for more information on other States' RPS programs.) Therefore, while some information is provided on other state RPS programs, a strict comparison of these programs will not be presented here.

REC definitions vary in what a REC fundamentally represents and the restrictions placed upon them. Some states limit the useful life of a REC (Colorado, Montana, New Mexico, Washington) while others allow an unlimited life (Arizona, Oregon, and Utah, California). Most states require that RECs be registered and tracked in WREGIS. However, Nevada uses portfolio energy credits (PECs) in order to meet energy portfolio requirements. Some states allow the trading of unbundled RECS, while others limit REC trading based on where the REC was actually created (Washington). Some states allow for an alternative compliance payment if an LSE does not meet the specific state obligations. Many states allow extra credit multipliers for early installation of certain technologies or give credit for green programs or investment in in-state solar facilities.

e. Out-of-State Unbundled RECs

The quantity of excess unbundled RECs from states within the WECC that could be used in the California RES is currently unknown. Some studies have forecasted the quantity of excess renewable energy that may be available for state RPS programs, or have modeled how allowing unbundled REC trading would affect the cost or renewable energy composition of meeting states' RPS targets.[14,15] As new renewable energy generation comes on-line and other states' RPS programs also ramp up, the renewable energy supply must first keep up with the demand created by regulatory programs before substantial quantities of excess RECs will be available for use in California.

f. Changes to WREGIS

Because WREGIS cannot currently accommodate the RES Qualifying POU Resources in the RES program, some changes to WREGIS will be required. One change will be to request a change control to allow a line item change to add in the RES Qualifying POU Resource as a field in the generating unit static data. An additional change will be to add a reason for retirement for these types of RECs as "CA RES" to the list of reasons for REC retirement. This will enable WREGIS to track the RES Qualifying POU Resources and retirement for the California RES program and to differentiate them from RPS eligible sources and California RPS retirement, respectively.

The process for this change is expected to take up to five months. This process begins by submitting a completed Change Control and Issue Request Form to the WREGIS staff requesting that the change be included on the agenda of the next monthly WREGIS Change Control Subcommittee meeting. The cost and scheduling to implement the change will be determined and reported back to the Change Control Subcommittee at the next monthly WREGIS meeting. After the content, cost and timing of the changes are agreed upon, the change request is taken to the WREGIS Committee for approval. After the change request is approved, it is estimated that the changes will take an additional month or two to be added to the system and fully tested. ARB staff will work closely with CEC staff to ensure these tasks are completed. CEC, as a Program Administrator account holder in WREGIS, has agreed to officially request the changes mentioned above.

7. Enforcement and Penalty Provisions

ARB will enforce the proposed RES program in consultation with CEC and CPUC to ensure that all regulated parties are in compliance with the proposed regulation. The proposed regulation contains enforcement and penalty provisions that differ from the existing RPS program. More information on these provisions is included in Chapter XII.

REFERENCES

[1] California Energy Commission, 2010. Utility Energy Supply Plans from 2009, http://energyalmanac.ca.gov/electricity/S-2_supply_forms_2009/

[2] California Energy Commission, 2010. California Energy Maps: California Electric Utility Service Areas, http://www.energy.ca.gov/maps/maps-pdf/UTILITY_SERVICE_AREAS_DETAIL.PDF

[3] Northern California Power Association, 2010. NCPA Retail Sales and Power Content Label Information – 2009

[4] ESP data: Public Utilities Commission, 2010. (CONFIDENTIAL)

[5] ARB, 2010. Threshold Determination Survey (CONFIDENTIAL)

[6] California Public Utilities Commission, 2009. Appendix A: PG&E's August 2009 RPS Compliance Report, http://www.cpuc.ca.gov/NR/rdonlyres/EBE57831-83F3-45A1-A6AD-859F3B77A64C/0/IOU_August_2009_RPS_PDSR_Public_PGE.pdf

[7] California Public Utilities Commission, 2009. Southern California Edison Company (U 338-E) August 2009 Semi-annual Compliance Report, http://www.cpuc.ca.gov/NR/rdonlyres/E045EB09-C540-480B-A1C9-B799062F92B6/0/IOU_August_2009_RPS_Compliance_Report_Public_SCE.pdf

[8] California Public Utilities Commission, 2009. San Diego Gas & Electric August 2009 Semi-Annual Compliance Report, http://www.cpuc.ca.gov/NR/rdonlyres/55682311-1E70-498E-AB0D-06E5F2CFBFEA/0/IOU_August_2009_RPS_Compliance_Report_Public_SDGE.pdf

[9] California Public Utilities Commission, 2010. RPS Project Status Table, http://www.cpuc.ca.gov/NR/rdonlyres/9AA867DE-3745-48D1-A740-B7B0BC2627A4/0/RPS_Project_Status_Table_2010_May.XLS

[10] California Public Utilities Commission, 2010. Confidential Information updating Status of RPS Projects.

[11] California Public Utilities Commission, 2009. Renewable Portfolio Standard Compliance Report Submitted by Bear Valley Electric Service A Division of Golden State Water Company, http://www.cpuc.ca.gov/NR/rdonlyres/1DC5E5B6-71DA-4435-BB82-539527633149/0/SM_August_2009_RPS_Compliance_Report_Public_BVES.pdf

The following references are all part of reference 11:

California Public Utilities Commission, 2009. August 2009 Compliance Report of Mountain Utilities' (U 906-E) Pursuant to the California Renewables Portfolio

Standard and Request for Waiver, http://www.cpuc.ca.gov/NR/rdonlyres/9EE9FFF1-B99C-4C4D-9ED7-A92C06DD103E/0/SM_August_2009_RPS_Compliance_Report_Public_MU.pdf

California Public Utilities Commission, 2009. August 2009 Semi-Annual Compliance Report of Pacificorp (U 901-E) Pursuant to the California Renewables Portfolio Standard, http://www.cpuc.ca.gov/NR/rdonlyres/E5E8D281-316A-4B40-8C40-272BD6DEA907/0/MJU_August_2009_RPS_Compliance_Report_Public_Pacificorp.pdf

California Public Utilities Commission, 2008. Sierra Pacific Power Company (U903E) August 2009 Semi-Annual Compliance Report Pursuant to the California Renewables Portfolio Standard, http://www.cpuc.ca.gov/NR/rdonlyres/92B67FA9-635D-4F8B-913D-4C797F0E3F28/0/MJU_August_2009_RPS_Compliance_Report_Public_Sierra.pdf

[12] California Public Utilities Commission, 2009. Decision Authorizing Use of Renewable Energy Credits for Compliance with California Renewables Portfolio Standard http://docs.cpuc.ca.gov/efile/PD/99016.pdf

[13] United States Department of Energy, 2008. Green Power Marketing, Green Power Marketers, http://apps3.eere.energy.gov/greenpower/markets/marketing.shtml?page=2

[14] National Renewable Energy Laboratories, 2009. An Examination of the Regional Supply and Demand Balance for Renewable Electricity in the United States through 2015, http://www.nrel.gov/docs/fy09osti/45041.pdf

[15] Ernest Orlando Lawrence Berkeley National Laboratory, 2010. Exploration of Resource and Transmission Expansion Decisions in the Western Renewable Energy Zone Initiative, http://eetd.lbl.gov/ea/ems/reports/lbnl-3077e.pdf

This Page Intentionally Left Blank

VIII. SUMMARY AND RATIONALE FOR THE PROPOSED REGULATION

In this chapter, we provide a discussion of the requirements of the proposed regulation and explain staff's rationale for each requirement. This chapter begins with a general overview of the regulation. Sections B through N follow the general structure of the proposed regulation and provide an explanation of each major requirement of the proposal to satisfy the requirements of Government Code section 11346.2, which requires that a "plain English" summary of the regulation be made available to the public. Section P follows the structure of the proposed regulation and provides the rationale for each provision.

A. Overview of the Proposed Regulation

The proposed regulation, referred to as the Renewable Electricity Standard (RES), requires California's retail sellers of electricity, to demonstrate, by 2020, that 33 percent of the electricity sold to their customers was generated from renewable energy resources. The California Department of Water Resources (DWR) and the Western Area Power Administration (WAPA) are included as regulated parties but are only required to report information on electricity transactions at this time. Increasing the portion of electricity supplied from renewable resources will reduce greenhouse gas (GHG) emissions by displacing electricity produced by fossil fuel-fired electrical generating facilities. The proposed regulatory language is contained in new sections 97000 through 97012 of title 17, California Code of Regulations (see Appendix A of this report).

Achievement of the 33 percent renewables standard is phased in through multi-year compliance intervals starting with the 2012 to 2014 time period. The RES would establish a renewables generation requirement that is determined by multiplying a utility's total retail electricity sales by the fraction of those sales that must come from renewable generation. Compliance with the percentage obligation is based on the acquisition and retirement of renewable energy credits, or RECs, that represent one megawatt-hour (MWh) of energy generated by an eligible renewable energy facility. The calculated number of RECs needed by a party to demonstrate compliance with the percentage obligation is known as its "RES Obligation." Parties that are subject to the regulation would meet the percentage of retail sales requirements if the amount of RECs retired at the end of the compliance period is equal to, or greater than, the percentage required during that period.

B. Purpose

The purpose of the proposed regulation is to reduce GHG emissions associated with the generation of electricity used to serve California, consistent with the ARB's authority under AB 32. GHG emissions would be reduced by increasing the fraction of electrical demand that is met by renewable resources. This will lower the overall carbon intensity of grid-supplied electricity over time. The proposed regulation is expected to achieve

reductions in GHG emissions of about 12 to 13 million metric tons of carbon dioxide equivalents ($MMTCO_2e$) in 2020 and thereafter.

C. Applicability

The proposed regulation would apply to the following regulated parties: local publicly owned electric utilities (POUs), electrical corporations (also known as investor owned utilities or IOUs), electric service providers, community choice aggregators, community aggregators, electrical cooperatives, DWR, and WAPA. A partial exemption is proposed for regulated parties that serve small loads (see next section). Any new regulated party that is formed after September 15, 2009 (the date Governor's Executive Order S-21-09 was signed), would automatically be subject to the requirements of the regulation regardless of the amount of total retail electric sales provided in any given year.[a]

The proposed regulation would not supersede the obligations that apply to electrical corporations and electric service providers under the existing California Renewables Portfolio Standard (RPS) Program. The procurement requirements, as well as the standards for RPS Program participation, certification, verification, and enforcement would remain intact and be implemented concurrently by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) with ARB's implementation of the proposed regulation.

D. Partial Exemption

The RES obligations and compliance intervals of the proposed regulation would not apply to regulated parties that annually provided 200,000 MWh or less of total electricity sales to retail end-use customers averaged over calendar years 2007 through 2009. However, regulated parties that qualify for this partial exemption would be required to comply with recordkeeping and reporting provisions to demonstrate eligibility for the exemption. In addition, a regulated party formed after September 15, 2009 (the date Executive Order S-21-09 was signed), is not eligible for a partial exemption.

Once a partially exempt regulated party's electricity sales to retail end-use customers exceed 200,000 MWh in any calendar year after 2009, the exemption expires and the regulated party is subject to all provisions of the proposed regulation commencing January 1st of the next calendar year. This loss of exemption is considered permanent and the exemption cannot be reinstated if retail sales drop below 200,000 MWh in any year thereafter. The calculation of the RES obligation for a previously exempt regulated party is different from other regulated parties and is explained in section F of this chapter.

[a] The regulation states that a regulated party formed after September 15, 2009, is not eligible for a partial exemption under section 97003.

E. Definitions

The proposed regulation contains many definitions to clarify the requirements. Only the key definitions are highlighted in this section. A full list of definitions can be found in the text of the proposed regulation.

1. Renewable Energy Credit (REC)

As described in Chapter VI (Renewable Energy Credits), a REC is a credit issued by the Western Renewable Energy Generation Information System (WREGIS) and represents a certificate of proof of the environmental attributes that one MWh of renewable energy was generated by a renewable energy facility. To create an eligible REC for use in California, a facility must generate renewable energy within the Western Electricity Coordinating Council (WECC) and demonstrate that it meets the eligible renewable energy resource criteria.

2. Eligible Renewable Energy Resources

A REC used for compliance with the proposed regulation must come from an eligible renewable energy resource. Under the proposed regulation, an eligible renewable energy resource must participate in the WREGIS tracking system. The following qualify as an eligible renewable energy resource under the RES:

- A renewable generating facility that is certified by the CEC as eligible for the California RPS Program;
- A renewable generating facility that meets the criteria for an RPS-eligible resource, excluding electricity delivery requirements;[b] and
- A renewable generating facility that meets the criteria for a RES Qualifying POU Resource (see definition below).

The three types of eligible renewable energy resource categories are described below.

Facility Certified by CEC as an RPS-Eligible Resource
To qualify as an eligible renewable energy resource under the RPS Program, the generating facility must be registered in the WREGIS tracking database and must be certified by the CEC as meeting the criteria for an RPS-eligible resource. A facility may be eligible for the RPS if it uses an eligible renewable resource or fuel,[c] satisfies resource-specific criteria, and is either located within the State or satisfies applicable requirements for out-of-state facilities. Facilities that have their first point of interconnection to the WECC transmission system within the State are considered to be

[b] This is different from the California RPS program, which requires delivery of an equivalent amount of electricity to California within the same calendar year. Refer to Chapter VI for more discussion on the differences between the RPS and proposed RES treatment of RECs.
[c] Information on eligible resource or fuel types is contained in Chapter IV and the CEC's Renewables Portfolio Standard Eligibility Guidebook.

in-state facilities. Out-of-state facilities that are not interconnected to the WECC transmission system are not eligible for the RPS.

Out-of-state facilities that have their first point of interconnection to the WECC transmission system outside the state must meet the following additional requirements:

- must be connected to the WECC transmission system;
- generally must have began operating after January 1, 2005;
- not cause or contribute to any violation of a California environmental quality standard or other applicable requirements within California, such as an ambient air quality standard; and,
- if located outside the United States, be developed and operated in a manner that is as protective of the environment as would a similar facility be if it were located in California.

CEC rules also require proof that a similar amount of energy was delivered to California before the REC from an RPS-eligible facility can be counted for compliance with the RPS. For renewable energy generated within California or directly delivered to a California balancing authority, the delivery requirement is automatically fulfilled. However, to count generation from other out-of-state facilities as being delivered, the renewable generator (the seller) and the buyer must enter into a contract, and the buyer must demonstrate that an equal amount of energy was delivered to California within the same calendar year. The power could be delivered at a different time in a calendar year than when the renewable energy generator originally produced it. Further, the electricity delivered into California could come from anywhere within the WECC from any type of generating facility.

Facility Meeting RPS Program Criteria with Exception of Delivery Requirement
Under the proposed RES, there is no requirement that the electricity produced by the facility be delivered to an in-state location. Therefore, facilities that meet all the requirements of an eligible renewable energy resource under the RPS Program, with the exception of delivery requirements, are eligible under the RES.

Facility Meeting Definition of a RES Qualifying POU Resource
The definition of a RES Qualifying POU Resource is described in the next section.

Other than the exceptions noted with respect to delivery requirements and facilities meeting the definition of a RES Qualifying POU Resource, the proposed regulation is intended to adopt the same criteria and definitions for eligible renewable energy resources that have been set forth in the CEC Renewables Portfolio Standard Eligibility Guidebook.

3. RES Qualifying Publicly Owned Utility (POU) Resource

A REC from a renewable resource that does not meet the criteria for an RPS-eligible resource may be used by a POU for compliance with the proposed RES regulation

under certain conditions. To differentiate these POU-only eligible resources from the current RPS Program, a new term was created, "RES Qualifying POU Resource," which is unique to the RES. First, to be eligible, the electrical generation from these resources must have been approved by the Governing Board of a POU and reported to the CEC as contributing toward the POU's RPS target on or after January 1, 2003 (the effective date of the RPS Program under Senate Bill 1078), and prior to September 15, 2009 (the date Governor's Executive Order S-21-09 was signed). In addition, the following conditions must be met:

- the POU must have owned the facility prior to or after January 1, 2003, and prior to September 15, 2009, or

- a contract to procure electricity from the facility must have been executed prior to September 15, 2009, and
  - the POU procured electricity and RECs, or RECs without electricity, and
  - the electricity was procured during the term of the contract and not during any contract term that was extended or modified after September 15, 2009.

Once the procurement contract expires, the RECs procured from the RES Qualifying POU Resource are no longer eligible for compliance with the RES and must be replaced with RECs from an eligible renewable energy resource, as discussed in section E.2 above.

F. Renewable Electricity Standard Obligations

This section describes the RES obligation requirements for regulated parties, previously exempt regulated parties, regulated parties with large hydroelectric generation, and the requirements for DWR and WAPA.

1. RES Obligation for Regulated Parties Other than DWR and WAPA

A regulated party's compliance with the RES renewables requirement is demonstrated through the retirement of RECs equivalent to a percentage of total retail electric sales to end-use customers that represent renewable generation. The 33 percent standard is phased-in over an eight-year period, starting on January 1, 2012, with four compliance periods, each with its own renewable energy percentage requirement. Table VIII-1 shows the interim REC percentage requirements and corresponding compliance interval dates.

Table VIII-1
Compliance Intervals and REC Percentages

Compliance Intervals	REC Percentage
2012 through 2014	20
2015 through 2017	24
2018 through 2019	28
2020 and annually thereafter	33

Compliance with the interim standards is based on calculating the regulated party's RES obligation (in MWh) and comparing that value to the number of WREGIS certificates retired (each certificate represents a REC). For 2012 through 2014 and 2015 through 2017, the RES obligation is calculated over the entire three-year interval to determine compliance. For 2018 through 2019, the RES obligation is calculated over the two years to determine compliance. For 2020 and beyond, compliance is determined on an annual basis. Although compliance with the interim standards is not assessed until the end of each reporting period, regulated parties must measure, track, and report their status annually. The RES obligation for a given compliance interval is determined using the following formula:

RES Obligation = Sum of retail sales for the compliance interval (in MWh) x the REC percentage for the compliance interval

RECs used to meet the RES obligations must be retired in WREGIS by March 31st of the year following the compliance interval.

2. RES Obligation for a Previously Exempt Regulated Party

A regulated party loses the exemption discussed above if its retail electric sales to end-use customers exceeds 200,000 MWh during any calendar year after 2009. At that point, the regulated party is subject to a RES obligation and must annually retire RECs by March 31st after the end of each calendar year in an amount equivalent to the total retail electric sales in excess of 200,000 MWh. This RES obligation is determined using the following formula:

RES Obligation = Total retail sales (in MWh) – 200,000 MWh

If the calculated RES obligation is less than zero, then there is no REC retirement obligation for that calendar year. In addition, no credit towards a future obligation will be given if the calculated RES obligation is less than zero. The annual RES obligation will apply to the regulated party until it meets or exceeds the RES obligation that is concurrently required from other regulated parties subject to the regulation (in Table VIII-1 above). At that point, the previously partially exempt regulated party will be subject to the same RES obligations as regulated parties that did not have a partial exemption.

3. RES Option for Regulated Parties with Large Hydroelectric Generation Other than DWR and WAPA

A regulated party that receives 67 percent or more of its electricity from hydroelectric generation that does not meet the proposed regulation's definition of an eligible renewable energy resource (i.e., large hydroelectric generation), and which was procured prior to September 15, 2009, has the option of electing to provide RECs for the remainder of the electricity it provides to its retail end-use customers. This RES obligation is determined using the following formula:

RES Obligation = Total retail sales (in MWh) – retail sales from hydroelectric generation (in MWh)

RECs used to meet the RES obligations must be retired in WREGIS by March 31st of the year following the compliance interval.

Depending on the MWh available from large hydroelectric generation in any given calendar year due to normal seasonal variation, the RES obligation could be less than, or in excess of, the REC percentages in Table VIII-1. This RES obligation applies to the same compliance intervals specified in Table VIII-1 above.

A regulated party that chooses to comply with this REC option must notify the ARB Executive Officer in writing of its intent to comply with the option by December 31, 2011. Once the regulated party selects this option, it cannot be changed or withdrawn.

4. Requirements for DWR and WAPA

DWR and WAPA do not have a RES obligation under the proposed regulation, but are subject to reporting requirements. By July 1, 2013, and by July 1st annually thereafter, they are required to report information to ARB for the prior calendar year on their electricity transactions.

G. Renewable Electricity Standard Requirements

RECs used for compliance with the proposed regulation must be registered in and tracked by WREGIS. Since RECs can be sold separately from the underlying electricity, the possibility for fraud can exist unless the RECs are tracked from their point of creation to their final point of use. WREGIS issues a uniquely numbered certificate for each MWh of electricity generated by a facility registered in the system and tracks the ownership of certificates as they are traded and retired. Tracking systems help avoid double counting and double claims. The proposed regulation requires that RECs used for compliance with the RES must be retired in WREGIS and specifies that they may not be used to meet the regulatory or voluntary requirements of any other federal, state, or local program ("secondary program"). However, a REC used for compliance with the California RPS would count toward compliance with the RES.

There are three types of RECs that may be used to comply with the proposed regulation:

- RECs from a renewable generating facility that is certified by the CEC as eligible for the California RPS Program;
- RECs from a renewable generating facility that meets the criteria for an RPS-eligible resource, excluding electricity delivery requirements; and
- RECs from a renewable generating facility that meets the criteria for a RES Qualifying POU Resource.

These three categories were described in detail in Section E above. The proposed regulation restricts the amount of RECs from a RES Qualifying POU Resource that may be used by the initial POU owner or procurer. This amount is capped at 20 percent of the POU's retail sales to end-use customers during calendar year 2010.

RECs used to meet the RES obligations must be retired in WREGIS. The process used to retire RECs in WREGIS for purposes of compliance with this requirement is described in Chapter XII (Implementation and Enforcement).

H. Banking and Trading of RECs

The proposed regulation provides a mechanism for both regulated and non-regulated parties (such as brokers) to bank and trade RECs. RECs that are not used by a regulated party to meet a current compliance obligation may be banked and applied toward that party's obligations in subsequent years or may be traded to other parties, including third party brokers not subject to the RES. Some additional trading restrictions are imposed. First, a REC is subject to a three-year retention and trading window – in other words, the WREGIS certificate associated with a REC may be retained or traded for up to three calendar years from the date WREGIS issued the certificate, including the certificate issuance year, or until the WREGIS certificate associated with a REC is retired into a WREGIS retirement subaccount, whichever of these events occurs first. Second, a WREGIS certificate associated with a REC must be moved to a WREGIS retirement subaccount within three years of its generation or acquisition to be used for RES compliance; however, WREGIS certificates placed in a retirement subaccount that are not used to meet a current RES obligation have an unlimited banking life. Third, a REC generated or procured from a RES Qualifying POU Resource may be banked by the original owner of the REC, but cannot be traded or sold. This restriction was imposed to preserve the environmental benefits of renewables voluntarily procured by exempted parties. As mentioned previously, energy from RES Qualifying POU Resources comes primarily from large hydroelectric facilities. Lastly, a REC generated or procured by an entity that qualifies for the partial exemption as a small regulated party may not be banked, traded, or sold.

The banking and trading restrictions imposed by the proposed regulation apply to RECs used to meet a RES obligation. They do not limit the use, banking, or trading of RECs that are not used to meet the requirements of the regulation.

I. Monitoring, Verification, and Compliance

As mentioned previously, the proposed regulation was developed to utilize, to the greatest extent feasible, the implementation mechanisms established by the CEC and CPUC for the existing California RPS Program and to avoid duplicative reporting and compliance verification processes for regulated parties. This includes carry-over of the certification procedures and requirements for eligible facilities whether located in- or out-of-state; procedures for verifying utility procurement and retail sales; continuing the same administrative roles for the CEC and CPUC, but also capturing the publicly owned utilities (POUs); and continuing all other basic monitoring and reporting procedures. Compliance determinations would be based on the number of WREGIS certificates retired. A detailed description of the recordkeeping and reporting provisions, as well as the procedures by which regulated parties are to file compliance documents is included in Chapter XII (Implementation and Enforcement).

J. Certification of Eligible Renewable Energy Resources

Certifying RPS-eligible facilities falls under the CEC's current statutory authority. The CEC certifies RPS-eligible facilities regardless of whether the energy and RECs are procured by parties subject to the RPS, by POUs, or by another entity. The CEC would continue this role after the adoption of the proposed regulation. Applicants seeking certification of a renewable energy facility for eligibility under the existing RPS Program would file the application with the CEC in accordance with their review process.

The CEC does not have statutory authority, however, to certify or register facilities for POUs (or any entity) that do not meet the statutory requirements for RPS-eligibility. Under the proposed regulation, this would include facilities not meeting the delivery requirement of the RPS Program and facilities eligible as a RES Qualifying POU Resource, in addition to the POU resources. These applicants would file the application with the ARB Executive Officer. However, ARB staff is exploring mechanisms by which the ARB would receive the application for non-RPS eligible facilities and enter into an interagency agreement with CEC or a third party contractor to review and make recommendations regarding certification and verification of the resource for the RES Program. A detailed description of the certification process and how ARB would utilize an interagency agreement or other mechanism to enable the CEC or a third party contractor to perform services and activities on programmatic matters common to both agencies is discussed in Chapter XII (Implementation and Enforcement).

K. Interagency Cooperation

The California Administrative Procedure Act requires that the proposed rulemaking harmonize with existing statutes or other provisions of law and provide for non-duplication of existing State or federal statute or another regulation. As mentioned previously, the proposed regulation was developed using the existing California RPS Program as a foundation. Therefore, in order to avoid duplication of recordkeeping,

reporting, monitoring, and verification requirements, ARB staff proposes to utilize the implementation mechanisms already established by the CEC and CPUC under the RPS Program. For program elements that are not already under the authority of the CEC or CPUC, the ARB's Executive Officer may enter into memorandums of understanding or interagency agreements with these agencies to assist in the implementation of the processes, procedures, and requirements of the proposed regulation. A discussion of how interagency cooperation would be utilized to streamline monitoring, verification, and compliance with the proposed regulation is included in Chapter XII (Implementation and Enforcement).

L. Enforcement

The proposed RES will be enforced by the ARB is cooperation with CEC and CPUC. A violation of the proposed requirements may result in civil or criminal penalties. The extent of the penalty would depend on the willfulness of the violation, the length of time of the noncompliance, the magnitude of the noncompliance, and other pertinent factors, consistent with the provisions outlined in the California Health and Safety Code. A description of what constitutes a violation under the proposed regulation, as well as penalties for non-compliance, and a discussion of enforcement authority is included in Chapter XII (Implementation and Enforcement).

M. Confidential Information

This section informs regulated parties under what circumstances information required to be submitted to ARB would be considered confidential.

N. Regulation Review

ARB staff is sensitive to the issue of cost containment as it pertains to the proposed regulation. In order to proactively and adequately respond to cost and other issues, ARB staff is incorporating regular, formal reviews of the RES into the proposed regulation. Staff will conduct at least three reviews to evaluate the effectiveness of the RES program, as well as the need for program modifications. These reviews will be done in consultation with the CEC, CPUC, CAISO, and other balancing authorities. The reviews would be completed and presented to the Board by December 31, 2013, December 31, 2016, and December 31, 2018. Each review will consider the following:

- regulated party progress against the applicable compliance interval targets;
- advances in renewable energy generation technologies, including storage technologies, and the feasibility and cost effectiveness of such advances;
- supply availabilities of renewable energy and RECs in the WECC;
- impacts of integrating variable renewable resources on the State's energy supplies and system reliability;
- impacts on electric rates, consumers, and economic growth;
- analysis of public health impacts, including operational impacts of generating facilities, demand response, and storage facility development;

- assessment of the air quality impacts on California associated with implementation of the regulation, including affects on attainment of State or federal air quality standards; and
- impact of renewable energy development barriers or delays encountered by regulated parties.

The reviews will also determine the need for program modifications, to include whether any adjustments to the compliance schedules are necessary to minimize costs and maximize benefits for California's economy, improve and modernize California's energy infrastructure, maximize potential greenhouse gas and criteria pollutant emissions reductions, and maintain electric system reliability. Opportunities to harmonize the program with any federal, regional, or other state RPS programs or REC markets will also be considered.

The reviews will be conducted using a public process and ARB staff will conduct at least one public workshop for each review prior to presenting the results to the Board. In conjunction with presenting review findings, the ARB Executive Officer will propose any amendments to the regulation or other program elements.

O. Severability

The proposed regulation contains a severability clause stipulating that in the event any portion of the proposed regulation is deemed invalid, the remainder of the proposed regulation would continue in full force and effect.

P. Rationale for the Proposed Regulation

This section briefly summarizes each section of the proposed regulation and provides the corresponding rationale for each provision.

Section 97000. Purpose

Summary of Proposed Regulation.
This section states the purpose of the regulation.

Rationale for Proposed Regulation.
This section is needed to ensure the regulated public understands that the proposed regulation will be used to reduce GHG emissions associated with the generation of electricity.

Section 97001. Applicability

Summary of Section 97001.
This section outlines that the requirements of the proposed regulation will apply to the regulated parties stated in subsection 97002(a)(15).

Rationale for Section 97001.
This section is required in order to identify the entities to which the proposed regulation would apply.

Section 97002. Definitions and Acronyms

Summary of Section 97002.
This section proposes definitions to the terms used in this regulation and defines the acronyms used in this regulation.

Rationale for Section 97002.
It is necessary that ARB defines its terms as they apply to the RES regulation. Many of these terms are used in the Public Utilities Code, and it is necessary that ARB be consistent with existing definitions to the extent that they apply to this regulation.

Section 97003. Partial Exemption

Summary of Section 97003(a).
This section specifies that a regulated party with annual electricity sales to retail end-use customers of 200,000 MWh or less, averaged during 2007 through 2009, is exempt from all but specific recordkeeping and reporting requirements of the proposed regulation.

Rationale for Section 97003(a).
Staff's analysis found that retail sellers that would qualify for the exemption are either already served by 100 percent hydroelectric resources or are so small that they do not have the staffing and budget to absorb the administrative burden of compliance with a 33 percent renewables requirement. Requiring these entities to spend additional funds to procure renewable energy or RECs would create a disproportionate use of resources relative to the environmental benefits, both for the retail seller and regulatory agency compliance staff. Staff also concluded that the 200,000 MWh threshold represents a reasonable threshold at which the cost of compliance is disproportionate to the potential environmental benefit.

Summary of Section 97003(b).
This section specifies that a regulated party that qualifies for the partial exemption must demonstrate eligibility for the exemption through tracking and reporting of annual retail electricity sales to end-use customers.

Rationale for Section 97003(b).
This section is necessary to require that a regulated party provide proof of eligibility for the partial exemption by reporting annual retail electricity sales to end-use customers.

Summary of Section 97003(c).
This section specifies under what conditions a regulated party no longer qualifies for the partial exemption, the effective date of the loss of exemption, and which requirements of the regulation apply once the exemption is lost.

Rationale for Section 97003(c).
The RES obligation requirements of the regulation are based on calendar year retail electricity sales to end-use customers. Therefore, staff determined that a regulated party that exceeds the 200,000 MWh partial exemption threshold in any year after 2009, should be required to comply with the regulation starting on the first day of the subsequent calendar year.

Summary of Section 97003(d).
This section specifies that a regulated party formed after September 15, 2009, does not qualify for the partial exemption.

Rationale for Section 97003(d).
This section is needed to ensure that new load serving entities do not circumvent the 33 percent renewables standard by forming multiple small customer service areas that are just under the 200,000 MWh partial exemption threshold. The September 15, 2009, date coincides with the signing of Executive Order S-21-09.

Section 97004. Renewable Electricity Standard Obligations

Summary of Section 97004(a).
This section requires a regulated party (other than DWR and WAPA) to retire WREGIS certificates in an amount equivalent to a specified percentage of its total retail electricity sales to end-use customers (RES obligation). The percentages are specified in Table 1of the proposed regultion and apply to single- to multi-year compliance intervals. The WREGIS certificates must be retired by March 31st of the year following the end of each compliance interval. This section also provides a formula to calculate the RES obligation.

Rationale for Section 97004(a).
Staff developed the proposed regulation as directed by Executive Order S-21-09, which requires a 33 percent renewables standard by 2020. Utilities have not met the 20 percent renewables by 2010 target established under the existing RPS Program. Therefore, staff determined that setting interim percent renewables requirements that increase in steady increments was necessary to ensure steady progress toward meeting the 33 percent standard by 2020. In addition, during the early years of the program, staff determined that three-year compliance intervals were reasonable to give regulated parties more flexibility in meeting the standards, accounting for unforeseen circumstances such as delay or cancellation of renewable project construction. The compliance intervals decrease in length to two-year and one-year durations in the later program years as staff believes by this time there should be more build out of additional renewable facilities.

Summary of Sections 97004(b)(1) and (2).
These subsections state the RES obligation for a regulated party that no longer qualifies for the partial exemption of section 97003. Parties that lose the exemption must annually retire WREGIS certificates by March 31st of the following year in an amount equivalent to the MWh in excess of 200,000 MWh. Once the party's RES obligation equals or exceeds the RES obligation calculated for a regulated party under subsection 97004(a), then the party must comply with subsection 97004(a).

Rationale for Sections 97004(b)(1) and (2).
These subsections are necessary to specify how a regulated party that loses an exemption is integrated into the RES. Staff determined that it may be overly burdensome and cost-prohibitive to automatically require a previously exempt party to comply with the RES obligations of subsection 97004(a). Staff determined that a more reasonable approach would be to require that load growth in excess of the exemption threshold (200,000 MWh) be met with renewable resources. Only at the point when load growth is sufficient enough to equal the RES obligations for other regulated parties, should these parties be required to meet the full requirements of the proposed regulation.

Summary of Section 97004(c)(1).
This subsection outlines an option for a regulated party that provides over 67 percent of its retail electricity sales to end-use customers from hydroelectric generation that does not meet the definition of an eligible renewable energy resource (i.e., large hydroelectric generation) and which was procured through ownership or contract executed prior to September 15, 2009. A regulated party that elects this option must retire WREGIS certificates by March 31st following the end of each compliance interval for 100 percent of the MWh not met by large hydroelectric generation.

Rationale for Section 97004(c)(1).
Although large hydroelectric generation does not meet the regulatory definition of an eligible renewable energy resource, it is nevertheless a renewable source of electricity with a beneficial air quality profile. If the 33 percent renewables requirement was imposed on a regulated party that already provides more than 67 percent of its electricity from large hydroelectric generation, then the party would be obligated to procure additional RECs from an eligible renewable energy resource with no additional GHG emissions benefit.

Summary of Section 97004(c)(2).
This subsection states that a regulated party that opts to comply with subsection 97004(c)(1) must make that selection by December 31, 2011, and cannot withdraw or change it once the selection is made.

Rationale for Section 97004(c)(2).
This option is tailored for regulated parties that have historically met a large portion of their electricity demand with large hydroelectric generation. It is not intended for parties

to float between requirements to reduce their RES obligation if they have a high large hydroelectric generation portfolio one year and a very low one in a subsequent year. Therefore, once the option is selected, it is considered binding.

Section 97005. Renewable Electricity Standard Requirements

Summary of Section 97005(a).
This subsection states that RECs must be tracked by WREGIS to be eligible towards a RES obligation.

Rationale for Section 97005(a).
Since RECs can be sold separately from the underlying electricity, the possibility for fraud can exist unless the RECs are tracked from their point of creation to their final point of use. WREGIS issues a uniquely numbered certificate for each MWh of electricity generated by a facility registered in the system, tracks the ownership of certificates as they are traded, and retires the certificates once they are used. Tracking systems help avoid double counting and double claims.

Summary of Section 97005(a)(1).
This subsection states that RECs used to comply with the proposed regulation may come from a generating facility certified as eligible for the RPS program.

Rationale for Section 97005(a)(1).
This subsection is consistent with the definition of an eligible renewable energy resource in the proposed regulation and is needed to make clear that RECs from certified RPS-eligible facilities qualify for the RES.

Summary of Section 97005(a)(2).
This subsection states that RECs used to comply with the proposed regulation may come from a generating facility that meets all the criteria of the RPS program with the exception of delivery requirements.

Rationale for Section 97005(a)(2).
This subsection is needed to make clear that RECs from facilities that meet all RPS criteria with the exception of delivery, qualify for the RES.

Summary of Section 97005(a)(3).
This subsection states that RECs used to comply with the proposed regulation may come from a RES Qualifying POU Resource as defined in the proposed regulation.

Rationale for Section 97005(a)(3).
This subsection is needed to make clear that RECs from facilities that meet the definition of a RES Qualifying POU Resource qualify for the RES.

Summary of Section 97005(b)(1).
This subsection states that WREGIS certificates must be retired in WREGIS to be eligible to demonstrate compliance with the proposed regulation.

Rationale for Section 97005(b)(1).
The act of transferring a WREGIS certificate to a WREGIS retirement subaccount takes the certificate out of circulation and helps avoid double counting. In addition, WREGIS issues a uniquely numbered certificate for each MWh of electricity generated by a facility registered in the system. The proposed regulation requires that regulated parties submit information on WREGIS certificates retired to meet a RES obligation by facility identification number. These unique identification numbers will be used to ensure that the same REC is not claimed under multiple programs.

Summary of Section 97005(b)(2).
This subsection states that WREGIS certificates retired to meet the California RPS Program can also be used to comply with the proposed regulation.

Rationale for Section 97005(b)(2).
Executive Order S-21-09 directed ARB to adopt a regulation consistent with the 33 percent renewables target established in Governor's Executive Order S-14-08. Executive Order S-14-08 was intended to increase the existing RPS Program requirement from 20 percent to 33 percent. This subsection is consistent with the Executive Orders by building upon the existing 20 percent RPS requirement rather than creating an additional overlapping requirement.

Summary of Sections 97005(b)(3)(i) and (ii).
These subsections state that a WREGIS certificate retired to comply with the RES cannot be used to meet any other federal, state, or local regulatory or voluntary program, and in the event that a regulated party attempts to use a certificate for RES and another program at the same time, then the certificate is deemed invalid for the RES.

Rationale for Section 97005(b)(3)(i) and (ii).
These provisions are necessary to prevent double counting and double claims between various programs, which would not increase the overall amount of renewable generation nor would it further reduce GHG emissions.

Summary of Section 97005(c).
This subsection allows the initial owner or procurer of RECs from a RES Qualifying POU Resource to use those RECs for an amount equivalent to 20 percent of its retail electricity sales to end-use customers in 2010.

Rationale for Section 97005(c).
POUs are encouraged but not required to meet the 20 percent renewables requirement under the existing RPS Program. Consequently, POUs are not subject to the same restrictions on eligible renewable energy resources prescribed under the RPS. They

are, however, required to meet the 33 percent standard under the RES, consistent with Governor's Executive Order S-21-09. In order to acknowledge actions taken under the RPS to increase renewables, the RES allows a POU to count otherwise ineligible resources (e.g., large hydroelectric generation) up to 20 percent of its retail sales, which is consistent with what the POUs have been allowed to do under the RPS.

Summary of Section 97005(d)(1).
This subsection establishes a three calendar year trading window for RECs from the date the certificate is issued by WREGIS or until a REC has been retired into a WREGIS retirement subaccount, whichever occurs first.

Rationale for Section 97005(d)(1).
Trading provisions among parties are allowed to facilitate compliance with the proposed regulation. However, the three-year window is included to prevent REC hoarding from causing artificial shortages. The three-year window was selected consistent with the tradable REC decision adopted by the CPUC.

Summary of Section 97005(d)(2).
This subsection requires that a REC be moved to a WREGIS retirement subaccount within three calendar years from the date WREGIS issues the certificate in order to be used to meet a RES obligation. Once it is moved to a WREGIS retirement subaccount, RECs not needed to meet a current RES obligation may be banked indefinitely to meet a future RES obligation.

Rationale for Section 97005(d)(2).
This requirement aligns with subsection 97005(d)(1), which establishes the three-year REC trading window. However, once a REC is committed to remain in a WREGIS retirement subaccount, staff believes it should not be limited to a specific compliance year or interval because that would create a disincentive for a regulated party to make forward-looking plans to meet a future RES obligation with excess RECs.

Summary of Section 97005(d)(3).
This subsection states that RECs from a RES Qualifying POU Resource can be banked by the original REC owner but cannot be traded or sold to another entity.

Rationale for Section 97005(d)(3).
RES Qualifying POU Resources are allowed under the RES to acknowledge progress made by POUs under the existing RPS Program using resources that do not qualify as eligible renewable energy resources but which are renewable nevertheless (primarily large hydroelectric generation). Therefore, the original owner should be allowed to use the RECs consistent with the RPS to meet their own RES obligation but should not profit from selling or trading them to other parties.

Summary of Section 97005(d)(1).
This subsection states that RECs generated or procured by a regulated party that is operating under the partial exemption are not eligible for sale, banking, or trading.

Rationale for Section 97005(d)(1).
Staff's analysis determined that parties that qualify for the partial exemption would be overly burdened by the cost of compliance with minimal GHG benefit. Therefore, it would create an inequity if these exempt parties were allowed to create or purchase RECs and sell, trade, or retain them for profit or to keep them out of circulation when they may otherwise be needed by parties that are subject to the 33 percent renewable requirement.

Section 97006. Monitoring, Verification, and Compliance

Summary of Section 97006(a).
This subsection requires each regulated party, with the exception of partially exempt parties and DWR and WAPA, to register with WREGIS.

Rationale for Section 97006(a).
WREGIS is the tracking system for RECs in the WECC and provides a way to track RECs from their creation to final use to avoid double counting and double claims.

Summary of Section 97006(b)(1)(A) through (C) and (2)(A) and (B).
These subsections require each regulated party, with the exception of partially exempt parties and DWR and WAPA, to file an achievement plan by July 1, 2012. These reports must include information about the regulated party and provide information about how the regulated party's plans to meet the 33 percent RES requirement by 2020.

Rationale for Section 97006(b)(1)(A) through (C) and (2)(A) and (B).
This information must be submitted to ARB so that ARB may track regulated party plans and actions in meeting their RES obligations and anticipate the need for program modifications through the periodic review process.

Summary of Section 97006(c)(1)(A) through (C) and (2)(A) and (B).
These subsections require each regulated party, with the exception of partially exempt parties and DWR and WAPA, to file annual progress reports starting July 1, 2013. The annual report must include information about the regulated party and provide information about the regulated party's progress toward the RES obligation achieved over the prior calendar year.

Rationale for Section 97006(c)(1)(A) through (C) and (2)(A) and (B).
This information must be submitted to ARB so that ARB may track the progress of the regulated parties in meeting their RES obligations, identify potential REC shortfalls, and anticipate the need for program modifications through the periodic review process.

Summary of Section 97006(d)(1)(A) through (C), (2)(A) through (E), (3), and (4)(A) and (B).
These subsections require each regulated party, with the exception of partially exempt parties and DWR and WAPA, to file compliance interval reports following the end of a

compliance interval. The compliance interval report must include information about the regulated party and provide sufficient information to determine whether the regulated party has demonstrated compliance with its RES obligation over the preceding compliance period. This information includes, but it not limited to, total retail sales to end-use customers over the compliance interval, the number of WREGIS certificates retired for the purpose of demonstrating compliance with the RES obligation, and the applicable subsection under which the regulated party calculated its RES obligation. Additional information is required if the compliance interval report indicates that the RES obligation was not met.

Rationale for Section 97006(d)(1)(A) through (C), (2)(A) through (E), (3), and (4)(A) and (B).
This information must be submitted to ARB so that ARB can verify compliance with the RES obligation for the applicable compliance interval and ensure that regulated parties that fall short of their RES obligation have a concrete schedule in place to come into compliance within the current reporting year.

Summary of Section 97006(e).
This subsection requires a partially exempt regulated party to annually report its total retail electricity sales to end-use customers starting July 1, 2013.

Rationale for Section 97006(e).
This provision is necessary to verify that the regulated party qualifies for the partial exemption based on calendar year retail electricity sales to end-use customers of 200,000 MWh or less.

Summary of Section 97006(f)(1) through (5).
These subsections establish the reporting requirements for DWR and WAPA. Specifically, DWR and WAPA report calendar year data of MWh of electricity procured under contract by specific generator name and type, or from a system power pool; MWh of electricity self-generated by source name and generator type; MWh of electricity consumed to convey, pump, and store water, or to serve individual water delivery contracts; MWh of electricity sales to retail end-use customers, by contract, from each generator source and type; and MWh of other wholesale or retail electricity sales, by contract, from each generator source and type.

Rationale for Section 97006(f)(1) through (5).
The primary business of DWR and WAPA is not the generation, transmission, and/or distribution of electricity for retail sale. DWR's primary role is water storage and delivery through its responsibility to operate and maintain the State Water Project. Electrical generation is a coincident benefit of this function. WAPA markets and transmits wholesale electric power generated at federal dams to federal and state agencies, rural electric cooperatives, municipalities, public utility districts, Native American tribes, and irrigation districts. These entities, in turn, provide retail electric services to consumers. At this juncture, staff determined DWR and WAPA should only be required to submit information on their electricity transactions to ARB. This information will be evaluated

and staff will determine (e.g., during the triennial review periods) if they should be subject to the same RES obligations as other regulated parties.

Summary of Section 97006(g).
This subsection states that all regulated parties must retain copies of records required by the proposed regulation for seven years, including those records that are necessary to verify the accuracy of information. Parties must allow inspection and duplication of this information or must provide the information within 30 days of a written request by the ARB Executive Officer or designee.

Rationale for Section 97006(g).
This requirement is necessary in the event any discrepancies or questions arise following report submittal.

Section 97007. Certification of Eligible Renewable Energy Resources

Summary of Section 97007(a)(1).
This subsection specifies which entities may certify a renewable facility as an eligible renewable energy resource under the RES. Specifically, CEC may certify a facility meeting the eligibility requirements for the RPS Program.

Rationale for Section 97007(a)(1).
Under the RPS Program, the CEC is responsible for certifying facilities as eligible renewable energy resources. RPS-eligible resources also qualify under the RES. Therefore, to avoid duplication and utilize existing CEC expertise, ARB would accept CEC-certified RPS resources as eligible under the RES.

Summary of Section 97007(a)(2).
This subsection specifies which entities may certify a renewable facility as an eligible renewable energy resource under the RES. Specifically, CEC may certify a facility that meets the eligibility requirements for the RPS Program, with the exception of the delivery requirement, under an interagency agreement with ARB.

Rationale for Section 97007(a)(2).
The RPS Program requires delivery of an equivalent amount of electricity to California within the calendar year for RECs purchased separately from the underlying electricity. This is not a requirement under the RES. Therefore, the CEC does not have statutory authority to certify facilities that do not meet the delivery requirements of the RPS. However, the CEC may instead certify these facilities under an interagency agreement with ARB. This provision is necessary to establish the mechanism by which the ARB could utilize existing CEC expertise to certify facilities that do not meet the RPS delivery requirement but that qualify for the RES.

Summary of Section 97007(a)(3).
This subsection specifies which entities may certify a renewable facility as an eligible renewable energy resource under the RES. Specifically, CEC may certify a facility that

qualifies as a RES Qualifying POU Resource under an interagency agreement with ARB.

Rationale for Section 97007(a)(3).
The RPS Program does not apply to POUs. POUs, however, are subject to the RES in accordance with the directive in Governor's Executive Order S-21-09. Therefore, the CEC does not have statutory authority to certify facilities for POUs. However, the CEC may instead certify these facilities under an interagency agreement with ARB. This provision is necessary to establish the mechanism by which the ARB could utilize existing CEC expertise to certify facilities that meet the definition of a RES Qualifying POU Resource.

Summary of Section 97007(a)(4).
This subsection states that the ARB Executive Officer or designee, or a third party contractor may certify a renewable facility as an eligible renewable energy resource using the same criteria that CEC would apply under subsections 97007(a)(2) or (3).

Rationale for Section 97007(a)(4).
In the event that the CEC does not have the resources to accommodate certification of non-RPS eligible facilities, this subsection is necessary to specify that ARB or a third party contractor could certify the facility using the criteria established by CEC.

Summary of Section 97007(b).
This subsection states that applicants seeking certification under the RPS Program must continue to file their application in accordance with that program's requirement.

Rationale for Section 97007(b).
This provision is necessary to clarify that facilities seeking RPS Program certification must continue to file with that program. The proposed regulation does not subsume the certification responsibilities under the RPS and transfer them to ARB.

Summary of Section 97007(c).
This subsection states that applicants seeking certification under the RES Program must file an application with the ARB Executive Officer. In turn, the Executive Officer may enter into an interagency agreement with CEC or a third party contractor to review and recommend or reject certification eligibility.

Rationale for Section 97007(c).
This provision is necessary to establish ARB as the entity responsible for certifying facilities that are not RPS-eligible and to establish that ARB may use an interagency agreement to allow CEC or a third party to assist ARB with certification.

Section 97008. Interagency Cooperation

Summary of Section 97008.
This section states that the ARB Executive Officer may enter into agreements with other parties, including the CEC and CPUC, to help with the implementation of the proposed regulation.

Rationale for Section 97008.
The CEC and CPUC collaboratively implement the existing RPS Program. ARB staff has used the RPS Program as a foundation for the development of the proposed regulation, and where feasible, has used the structure, provisions, policies, and implementation mechanisms established by the CEC and CPUC. The expertise in certifying eligible renewable facilities, verifying utility procurement and retail sales, already exists within the program staff at these agencies. Therefore, ARB staff intends to utilize the expertise of CEC and CPUC staff in implementing the proposed regulation.

Section 97009. Enforcement

Summary of Section 97009(a).
This subsection provides for the penalties and consequences of not complying with the proposed regulation. These provisions include penalties pursuant to Health and Safety Code section 38580 et seq.

Rationale for Section 97009(a).
This provision provides clarification as to the basis for the calculation of penalties.

Summary of Section 97009(b)(1).
This subsection establishes that each day a regulated party does not comply with a requirement of the proposed regulation is considered a separate violation.

Rationale for Section 97009(b)(1).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding.

Summary of Section 97009(b)(2)
This subsection specifies that where a regulated party fails to retire a sufficient number of WREGIS certificates to meet its RES Obligation by any Compliance Deadline, each required WREGIS certificate that was not retired is a separate violation.

Rationale for Section 97009(b)(2)
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding.

Section 97010. Treatment of Confidential Information

Summary of Section 97010.
This section informs regulated parties under what circumstances information required to be submitted to ARB would be considered confidential.

Rationale for Section 97010.
Utilities consider some of their data confidential. Therefore, this provision is intended to accommodate requests for confidentiality to the extent that they meet the criteria established in the California Code of Regulations, title 17, sections 97000 through 91022.

Section 97011. Regulation Review

Summary of Section 97011.
This section requires that ARB staff conduct triennial reviews of the regulation in cooperation with the State's primary energy entities. The reviews are conducted using a public process and the findings are to be presented to the Board.

Rationale for Section 97011.
The RES is considered a major regulation with cost in excess of $10 million, and therefore, ARB staff is sensitive to the issue of cost containment. The regular program reviews will enable staff to make program and regulatory modifications as necessary to address cost and other implementation issues.

Section 97012. Severability

Summary of Section 97012.
This section ensures that if one provision of the regulation is declared invalid by a court or other authority, the remaining provisions will remain in full force and effect.

Rationale for Section 97012.
This section is necessary to ensure that if ARB has enacted a provision in the proposed regulatory article that is illegal or unconstitutional, the remaining regulatory provisions remain intact in order to ensure the maximum environmental benefits of the proposed regulation.

This Page Intentionally Left Blank

IX. ENVIRONMENTAL IMPACTS

This chapter presents the environmental benefits and impacts associated with meeting the proposed 33 percent RES regulation (proposed RES). The analysis compares the impacts of requiring 33 percent of electricity retail sales to be from renewable generation in 2020 to the existing requirements for the 20 percent Renewable Portfolio Standard (RPS). This analysis shows that the proposed RES will reduce greenhouse gas (GHG) emissions throughout the Western Electricity Coordinating Council (WECC) by displacing electricity produced by fossil fuel-fired electrical generating facilities. The proposed RES is also expected to provide an overall air quality benefit by reducing statewide emissions of criteria and toxic air pollutants. Some renewable resources, such as wind and solar, require backup power from natural gas-fueled power plants because they do not generate electricity continually. The need for backup power reduces the benefits of these renewable resources and may also create some localized air impacts, depending on the type of load-following generation that is used. However, no significant adverse air quality impacts are expected from the proposed RES.

The California Environmental Quality Act (CEQA) and ARB policy require an analysis to determine the potential environmental impacts of the proposed regulation. ARB's program for adopting regulations has been certified by the Secretary of Resources, pursuant to Public Resources Code section 21080.5.[1] Consequently, the CEQA environmental analysis requirements may be included in the Initial Statement of Reasons (ISOR or "staff report") for this regulation. In the staff report, the ARB must include a functionally equivalent document, rather than adhering to the format described in CEQA of an Initial Study, a Negative Declaration, and an Environmental Impact Report. In addition, staff will respond to all significant environmental issues raised by the public during the 45 day public review period or at the Board hearing in the Final Statement of Reasons for the proposed regulation.

Public Resources Code section 21159 requires that the environmental impact analysis conducted by ARB include the following:

- An analysis of reasonably foreseeable environmental impacts of the methods of compliance;
- An analysis of reasonably foreseeable feasible mitigation measures; and
- An analysis of reasonably foreseeable alternative means of compliance with the proposed regulation.

Compliance with the proposed regulation is expected to directly affect air quality and potentially affect other environmental media as well. Staff's analysis of the reasonably foreseeable environmental impacts of the methods of compliance is presented in Sections C, D and E.

The proposed RES establishes non-prescriptive, performance based standards. Regulated parties have the flexibility to procure electricity from a mix of renewable resources to achieve the 33 percent target. Consequently, the specific compliance

scenarios chosen by industry to comply with the RES are uncertain. The GHG benefits (see Section B) can be estimated based on the possible mix of renewable projects that will come on-line over time. In addition, potential air quality impacts, both criteria pollutants and toxics, can be evaluated based on various compliance scenarios. As part of the air quality analysis, staff has estimated criteria pollutant emissions from the production and distribution of renewable generation in California and evaluated potential mitigation options in Section C. The public health impacts associated with the proposed RES are discussed in Section D. A discussion of the potential impacts on communities that are already impacted by air pollution is contained in Section E. Appendix D describes the methodology for assessing air quality impacts.

In addition to the GHG emission benefits and air quality analyses, the staff has evaluated other potential environmental impacts (see Section F). These non-air impacts include potential effects on land, water, biology, cultural, and visual resources. The ARB hired Ascent Environmental to assist with the analysis of non-air environmental impacts from new renewable generation facilities and transmission in California. The contractor performed a qualitative assessment of environmental impacts from out-of-state renewable generation. This analysis is provided in Appendix E. Staff summarized key findings from the consultant's analysis and incorporated them in Section F of this chapter. The environmental impacts of alternatives to the proposed RES are included in Chapter XI and Appendix G.

A. Summary of the Environmental Analysis

The environmental analysis of the proposed RES assesses the GHG emission reductions that would result from the proposed regulation. These reductions are based on operating emissions from the mix of renewable technologies in the compliance scenarios that were analyzed using the RES Calculator as discussed in Chapter V. As mentioned in that chapter, ARB staff used the RES Calculator to create and analyze possible compliance scenarios to illustrate a range of potential renewable resource mixes that could provide power to the California grid in 2020 based on the proposed RES requirements. These scenarios serve to identify potential types and regional locations of new renewable resources. The GHG emission reductions would result from reduced fossil-fueled electricity generation that is displaced by renewable generation in the WECC region.

Staff has estimated the WECC-wide reduction in GHG emissions from the existing 20 percent RPS to the proposed RES to be 13 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) by 2020 for the high load forecast and 12 $MMTCO_2e$ for the low load forecast. These GHG emission reduction estimates are consistent with the Scoping Plan estimate for the GHG benefits associated with increasing the renewable generation level from 20 percent to 33 percent. This estimate was about 13 $MMTCO_2e$ for a 13 percent renewable generation increase.[a]

[a] In the Scoping Plan, the GHG emission benefits associated with increasing the renewable generation level from 12 percent to 33 percent (i.e., 21 percent increment) are 21.3 $MMTCO_2e$. This represents about one $MMTCO_2e$ GHG emission benefit per one percent renewable generation increment.

Overall, the expected mix of renewable generation produces substantially less criteria pollutant and toxic emissions per unit of electricity output than the fossil-fuel generation it will displace in the possible compliance scenarios. As a result, the proposed RES regulation is expected to benefit air quality by reducing statewide emissions of criteria and toxic air pollutants.

To meet the proposed RES regulation, ARB staff estimates an additional 36,000 GWh of renewable power generation will be needed in 2020 for the high load forecast and 29,000 GWh will be needed for the low load forecast (see Chapter V for a discussion of the high and low load forecasts). In some cases, renewable generation will require development of new transmission lines. Criteria pollutant emissions were estimated for the production and transmission of electricity. Consistent with the anticipated air permitting requirements for new facilities in California, the emissions estimated for new renewable generation facilities reflect the use of the cleanest energy conversion and air pollution control technologies. The criteria pollutant and toxic emissions associated with new renewable generation facilities will be subject to air district permitting and CEQA requirements. If the new facility is located on federal land, it will also be subject to federal requirements under the National Environmental Policy Act (NEPA).[2]

ARB is committed to making the achievement of fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies an integral part of the proposed RES. As such, staff evaluated the proposed regulation to determine if it disproportionately affects local communities, or interferes with the attainment and maintenance of ambient air quality standards. As part of the RES analysis, staff used the proposed screening method for geographically representing emission densities, air quality exposure metrics, and indicators of vulnerable populations as an evaluation aide for communities that are adversely impacted by air pollution.

Also included in the environmental analysis is an examination of other potential environmental impacts on land use, water quality and use, biological, cultural, and visual resources, among others. Possible approaches to mitigate or minimize these effects are included in the analysis.

Lastly, ARB staff evaluated two alternatives to the proposed regulation as required by the CEQA guidelines. Staff analyzed the "no project" alternative, which includes only the implementation of the 20 percent RPS in 2020. This alternative is the same as the "business as usual" (BAU) scenario described in Chapter V. Staff also analyzed a 33 percent alternative that would require all of the renewable resources for the increment from the 20 percent RPS to the 33 percent target to be generated in California. The environmental impacts of these alternatives are discussed in Chapter XI and Appendix G.

B. GHG Emission Benefits from Renewable Generation

This section discusses staff's evaluation of the greenhouse gas (GHG) emission reduction estimates from various types of renewable generation, including the development of emission reduction factors.

1. GHG Emission Factors

The GHG emission reduction for each renewable resource or technology is based upon the "net" GHG emissions from the renewable generator technology, the GHG emissions associated with the operation of the renewable resource or technology, and the GHG emissions associated with the incremental displacement of fossil fuel generation in the WECC that occurs as new renewable energy resources are added. The focus of this assessment is to determine the direct emissions from the renewable resource and the fossil fueled generation they displace. It is not the intent to conduct a lifecycle analysis for each renewable or fossil fueled generator technology.

The net GHG emissions are the difference between the GHG emissions from using the renewable resource in an energy technology to generate a MWh of power, and GHG emissions from the typical use or disposal of the same amount of renewable resource. Some technologies utilizing renewable resources do not emit GHGs; therefore, the net GHG emissions for these technologies are zero. In the case where biomass is combusted directly to generate electricity, staff concluded that the GHG emissions would be very similar if the biomass were allowed to decay in its natural environment or if the biomass were combusted in an energy device; consequently, the net GHG emissions are zero. Because landfills emit both methane (CH_4) and carbon dioxide (CO_2), any technology that involves the use of landfill gas must include the impact of converting CH_4 to CO_2 when determining the net GHG emissions (methane is 21 times more potent as a GHG than CO_2, and technologies that convert methane to CO_2 are beneficial). Finally, some technologies, such as geothermal power plants, may emit CO_2 that otherwise would have been effectively sequestered in the local geological features accessed by the geothermal facility.

Staff evaluated GHG emissions from material transport and operation and maintenance activities at eligible renewable technologies. Staff determined that, except for transportation used to deliver biomass fuel to biomass combustion plants, the GHG emissions related to transportation and operation and maintenance are minor.

The major benefit from using renewable power is the displacement of power produced by burning carbon-based fuels that would otherwise be used to meet the demand on the utility grid. For the most part, the power being displaced is incremental power provided by generators to address load changes ("marginal power"), which is typically provided by natural gas power plants. This generation will likely be a combination of new combined cycle combustion turbines (CCCT) and new combustion turbines (CT). The California Public Utilities Commission (CPUC) expects that the marginal power will come from CCCT 95 percent of the time and from CT five percent of the time. Based

on this ratio, the GHG emissions associated with the marginal power would be 830 pounds of carbon dioxide equivalent per megawatt hour (lbs CO_2e/MWh). Staff will use this value as the GHG reduction resulting from the displacement of one MWh of generation from the grid by renewable resources.

2. GHG Emission Reduction Estimates

In this section, ARB staff presents the estimates of the GHG impacts associated with the proposed RES regulation. The GHG emission estimates include all areas interconnected within the WECC.

Table IX-1 compares the GHG emissions in 2020 under the 20 percent RPS scenario ("no project") to the GHG emissions under the proposed RES for the WECC-wide regions that supply power to California. This comparison is based on electricity production required under both scenarios (see Tables IX-2 and IX-3) and GHG emission factors. The details of the analysis are provided in Appendix D. This table shows the GHG emissions in 2020 would be reduced by 13 $MMTCO_2e$ under the proposed RES scenario for the high load and by 12 $MMTCO_2e$ for the low load scenario. These reductions are split almost equally between in-state and out-of-state regions (see Appendix D).

Table IX-1
WECC-Wide GHG Emissions and Emissions Reductions in 2020
20 Percent RPS vs. Proposed 33 Percent RES

WECC-wide Scenario	$MMTCO_2e$/yr	
	High Load	Low Load
Emissions with 20% RPS	88	67
Emissions with Proposed 33% RES	75	55
Emission Reductions	**13**	**12**

C. Air Quality Impacts

This section discusses the potential air quality impacts related to renewable generation facilities that may be constructed to meet the proposed RES regulation. These facilities include, but are not limited to, the following technologies: wind turbines, solar thermal, solar photovoltaic (PV), geothermal, solid-fuel biomass, landfill/digester gas, and small-scale hydropower (small hydro). Below are descriptions of the pollutants of interest in this chapter:

- Criteria Air Pollutants: Criteria air pollutants are determined to be hazardous to human health and are regulated under U.S. EPA's National Ambient Air Quality Standards. The 1970 amendments to the Clean Air Act require U.S. EPA to describe the health and welfare impacts of a pollutant as the "criteria" for inclusion in the regulatory regime. Both the California and federal governments

have adopted health-based standards for the criteria pollutants that include ozone, particulate matter (10 microns or less in diameter, PM_{10} and 2.5 micron or less in diameter, $PM_{2.5}$), carbon monoxide (CO), nitrogen dioxide (NO_2), and sulfur dioxide (SO_2).

- Toxics: Toxic air pollutants (also referred to as toxic air contaminants (TAC), or toxics) are those pollutants which may cause or contribute to an increase in mortality or serious illness, or which may pose a hazard to human health. However, their high toxicity or health risk may pose a threat to public health even at very low concentrations.

1. Overview of the Air Quality Analysis

This analysis evaluates the statewide, regional, and, to the extent practical, local air quality impacts resulting from changes in criteria pollutant and toxic air contaminant emissions that accompany implementing the proposed RES. For the proposed RES possible compliance scenarios, the analysis evaluates the air quality impacts of increasing renewable electricity generation from 20 percent to 33 percent of retail sales in 2020. The results of the analysis indicate that the proposed RES is expected to provide an overall air quality benefit by reducing statewide emissions of criteria and toxic air pollutants.

To evaluate the air quality impacts of the scenarios, staff used the current version of the E3 RES Calculator. The estimates of GHG and criteria pollutant emissions for the 20 percent RPS and proposed RES scenarios are based on electricity generation data from the RES Calculator and ARB developed emission factors. The RES Calculator develops electricity resource estimates for meeting a renewable generation target in California by 2020 by selecting resources from in-state and out-of-state CREZs, including 31 zones found within California and 13 out-of-state zones found within the WECC. The RES Calculator then deploys new renewables in selected CREZs until the specified renewable generation is met for a given load forecast.

As shown in Tables IX-2 and IX-3, total electricity production to meet California demand in 2020 is estimated to be about 340,000 gigawatt-hours (GWh) for the high load scenario and about 283,000 GWh for the low load scenario. The high load and low load scenarios are based on the CEC's 2009 Integrated Energy Policy Report[3] load forecast and were used to evaluate the additional renewable energy needed to meet the 33 percent target. The high load scenario uses historical data to draw assumptions and includes estimates of generation from combined heat and power (CHP) and solar distributed generation (DG), including rooftop and wholesale sources. However, the high load scenario does not include load reductions from fully successful implementation of several AB 32 Scoping Plan[4] measures, primarily expanded energy efficiency, CHP, and solar DG. The low load scenario reflects changes to the load attributable to full implementation of these Scoping Plan measures, using the high load estimates as a base case. This would result in a 17 percent decrease in retail sales in

2020, and an accompanying reduction in the renewable generation needed to comply with a 33 percent requirement.

Tables IX-2 and IX-3 are a direct output from the RES Calculator rounded to three significant figures. For a given load, the total generation for the 20 percent RPS and proposed RES scenarios differ slightly due to differences in transmission losses. In these tables, the sum of the individual resources may not be exactly equal to the total due to rounding. Also, the proposed RES requires 33 percent of retail sales to be generated by renewable resources, not 33 percent of total generation. Thus, total generation by renewables under the proposed RES scenario is not expected to equate to 33 percent of total generation.

Table IX-2
Projected Electricity Production in 2020
High Load Scenario

Resource	GWh			
	20% RPS		Proposed 33% RES	
	California	Out-Of-State	California	Out-Of-State
EXISTING:				
Traditional Sources	**139,000**	**84,100**	**125,000**	**72,300**
Natural Gas Peaker	10,500	8,120	8,420	6,470
Natural Gas Baseload	55,100	45,600	43,200	35,500
Nuclear	32,600	8,490	32,600	8,490
Large Hydro	39,900	2,630	40,000	2,630
Coal	1,320	19,300	1,300	19,300
Renewable Sources	**28,800**	**2,470**	**28,800**	**2,470**
Wind	5,720	504	5,720	504
Solar Thermal	724	0	724	0
Solar PV	0	0	0	0
Geothermal	12,900	740	12,900	740
Solid-Fuel Biomass	5,720	536	5,720	536
Landfill/Digester Gas	0	0	0	0
Small Hydro	3,730	688	3,730	688
NEW:				
Traditional Sources	**37,500**	**16,800**	**32,400**	**13,200**
Natural Gas Peaker	16,600	3,970	11,600	3,190
Natural Gas Baseload	20,900	12,800	20,900	10,000
Renewable Sources	**20,400**	**9,570**	**55,200**	**10,900**
Wind	7,620	5,860	17,300	6,990
Solar Thermal	2,500	2,440	13,800	2,440
Solar PV	1,060	22	3,330	22
Geothermal	6,540	680	18,100	680
Solid-Fuel Biomass	1,150	12	1,150	236
Landfill/Digester Gas	1,310	16	1,310	16
Small Hydro	214	543	214	543
TOTAL RENEWABLES	**49,200**	**12,000**	**84,000**	**13,400**
TOTAL	**226,000**	**113,000**	**242,000**	**99,000**

Table IX-3
Projected Electricity Production in 2020
Low Load Scenario

Resource	GWh			
	20% RPS		Proposed 33% RES	
	California	Out-Of-State	California	Out-Of-State
EXISTING:				
Traditional Sources	**119,000**	**67,000**	**107,000**	**57,500**
Natural Gas Peaker	7,570	5,810	5,870	4,480
Natural Gas Baseload	37,400	30,800	27,700	22,600
Nuclear	32,600	8,490	32,600	8,490
Large Hydro	40,000	2,630	40,000	2,630
Coal	1,300	19,300	1,300	19,300
Renewable Sources	**28,800**	**2,470**	**28,800**	**2,470**
Wind	5,720	504	5,720	504
Solar Thermal	724	0	724	0
Solar PV	0	0	0	0
Geothermal	12,900	740	12,900	740
Solid-Fuel Biomass	5,720	536	5,720	536
Landfill/Digester Gas	0	0	0	0
Small Hydro	3,730	688	3,730	688
NEW:				
Traditional Sources	**29,400**	**11,800**	**25,500**	**8,980**
Natural Gas Peaker	8,520	2,910	4,620	2,280
Natural Gas Baseload	20,900	8,890	20,900	6,700
Renewable Sources	**14,700**	**9,480**	**42,600**	**10,900**
Wind	2,730	5,860	17,300	6,990
Solar Thermal	1,820	2,440	13,000	2,440
Solar PV	999	22	3,170	22
Geothermal	6,490	680	6,490	680
Solid-Fuel Biomass	1,150	0	1,150	236
Landfill/Digester Gas	1,310	0	1,310	16
Small Hydro	214	478	214	543
TOTAL RENEWABLES	**43,500**	**11,900**	**71,400**	**13,400**
TOTAL	**192,000**	**90,700**	**204,000**	**79,800**

Tables IX-2 and IX-3 show that increasing the required renewable generation from 20 percent to 33 percent leads to expected decreases in generation from both new and existing natural gas plants in the year 2020. Wind and solar are projected to make up about 70 percent of all additional renewable generation procured by regulated parties to comply with the proposed RES for the high load forecast. Geothermal and other sources represent the remaining 30 percent. For the low load forecast, wind and solar resources represent almost all of the additional renewable generation.

2. Statewide Criteria Pollutant Emissions

The criteria pollutant emission estimates include emissions from all fossil-fueled and renewable electricity generation in California. Criteria pollutant emissions were estimated by applying resource-based emission factors to the electricity generation values presented in the previous section. A detailed description of this methodology is in Appendix D. The criteria pollutant emission factors are based on historical emission data from ARB's emission inventory and environmental impact reports.

Sources of criteria pollutants from the renewable energy resources included in the possible compliance scenarios are briefly summarized below:

Solar Thermal
Criteria pollutants are emitted from on-site boilers used to warm up the working fluid or provide additional heat to augment the heat provided by solar radiation. If wet cooling is used instead of dry cooling, cooling towers can be sources of PM emissions.

Geothermal
Dry steam and flash steam geothermal systems can emit significant amounts of CO_2, nitrogen oxides (NO_x), SO_2, PM, hydrogen sulfide, ammonia, CH_4 and radon gas. The type and quantity of the pollutants depends on the geology of the wells feeding the plant and the design of the plant. In addition, cooling towers can emit PM.

Solid-Fuel Biomass
In this report, solid-fuel biomass is also called biomass (see Chapter V). There are two types of biomass combustion: wood-fired boilers and fluidized bed combustors (FBC). These combustion systems use advanced air pollution control systems to significantly reduce emissions of NO_x, sulfur oxides (SO_x), and PM. Control systems include thermal denox to reduce NO_x emissions or a baghouse to reduce PM emissions. Additional PM can be emitted from the waste handling system.

Landfill/Digester Gas
In this report, landfill/digester gas is also referred to as biogas (see Chapter V). Landfill gas is a combination of methane and CO_2 plus some impurities such as hydrogen sulfide. These pollutants result from the anaerobic breakdown of the biogenic portion of waste placed in landfills. In California, air quality regulations require most large landfills to add gas collection systems and destroy the organic fraction of the collected gas, typically with a flare. In some cases, the gas flow is great enough to install an energy recovery system, such as an engine or combustion turbine, to generate electricity. The energy recovery systems emit significantly more NO_x emissions than a flare. Because of the impurities in landfill gas, typical control techniques, such as catalytic controls, cannot be used to reduce the NO_x emissions. Consequently, to mitigate these emissions impacts, the engines and turbines with the lowest emissions have been used in landfill gas-to-energy systems. The engines with the lowest NO_x emissions are lean-burn engines. Similarly, the turbines used in landfill gas-to-energy systems use low-emission combustion systems. While these requirements mitigate emission

impacts to a degree, emissions such as NO_x are about five times higher for biogas applications than the same equipment fueled with pipeline quality natural gas.

Digester gas, a combination of methane and CO_2 plus some impurities, results from the anaerobic breakdown of biogenic waste from digesters located at wastewater plants or dairies. The digesters need heat to operate properly. The digester gas can be used in a boiler to provide heat to a digester or an engine to provide both heat to the digester and generate electricity. Alternatively, the gas can be used to power fuel cells for distributed generation. This promising technology provides clean and efficient electricity generation without combusting the fuel. The same concerns regarding emissions from energy recovery systems used at landfills also apply to energy recovery systems at waste water plants.

Wind, Solar PV and Small Hydro
The electricity generated by wind turbines, solar PV panels and small hydro power does not directly emit any criteria pollutants.

Tables IX-4 and IX-5 show the 2020 statewide criteria pollutant emission estimates in tons per year (tons/yr) for the high load forecast for the 20 percent RPS and proposed RES, respectively. These criteria pollutants include reactive organic gas (ROG), NOx, SOx, CO, and $PM_{2.5}$. These values have been rounded to three significant figures.

Table IX-4
2020 Statewide Criteria Pollutant Emissions from Electricity Generation:
20 Percent RPS, High Load Forecast

Resource	CA Power Generation (GWh)	Emissions (tons/yr)				
		ROG	NO_x	SO_x	CO	$PM_{2.5}$
EXISTING:						
Traditional Sources						
Natural Gas Peaker	10,500	369	2,110	105	2,110	316
Natural Gas Baseload	55,100	1,100	2,760	276	2,760	1,100
Nuclear	32,600	0	0	0	0	0
Large Hydro	39,900	0	0	0	0	0
Coal	1,320	13	2,570	790	4,670	329
Renewable Sources						
Wind	5,720	0	0	0	0	0
Solar Thermal	724	11	72	1	15	11
Solar PV	0	0	0	0	0	0
Geothermal	12,900	194	19	6	5	194
Solid-Fuel Biomass	5,720	572	5,150	1,140	21,500	1,140
Landfill/Digester Gas	0	0	0	0	0	0
Small Hydro	3,730	0	0	0	0	0
NEW:						
Traditional Sources						
Natural Gas Peaker	16,600	166	831	166	1,660	499
Natural Gas Baseload	20,900	209	730	104	1,040	313
Renewable Sources						
Wind	7,620	0	0	0	0	0
Solar Thermal	2,500	13	5	1	6	8
Solar PV	1,060	0	0	0	0	0
Geothermal	6,540	7	10	0	1	65
Solid-Fuel Biomass	1,150	6	231	58	115	231
Landfill/Digester Gas	1,310	262	196	0	1,240	20
Small Hydro	214	0	0	0	0	0
TOTAL	**226,000**	**2,920**	**14,700**	**2,650**	**35,100**	**4,230**

Table IX-5
2020 Statewide Criteria Pollutant Emissions from Electricity Generation:
Proposed 33 Percent RES, High Load Forecast

Resource	CA Power Generation (GWh)	Emissions (tons/yr)				
		ROG	NO_x	SO_x	CO	$PM_{2.5}$
EXISTING:						
Traditional Sources						
Natural Gas Peaker	8,420	295	1,680	84	1,680	253
Natural Gas Baseload	43,200	864	2,160	216	2,160	864
Nuclear	32,600	0	0	0	0	0
Large Hydro	40,000	0	0	0	0	0
Coal	1,300	13	2,530	778	4,600	324
Renewable Sources						
Wind	5,720	0	0	0	0	0
Solar Thermal	724	11	72	1	15	11
Solar PV	0	0	0	0	0	0
Geothermal	12,900	194	19	6	5	194
Solid-Fuel Biomass	5,720	572	5,150	1,140	21,500	1,140
Landfill/Digester Gas	0	0	0	0	0	0
Small Hydro	3,730	0	0	0	0	0
NEW:						
Traditional Sources						
Natural Gas Peaker	11,600	116	579	116	1,160	347
Natural Gas Baseload	20,900	209	730	104	1,040	313
Renewable Sources						
Wind	17,300	0	0	0	0	0
Solar Thermal	13,800	69	28	6	35	41
Solar PV	3,330	0	0	0	0	0
Geothermal	18,100	18	27	1	2	181
Solid-Fuel Biomass	1,150	6	231	58	115	231
Landfill/Digester Gas	1,310	262	196	0	1,240	20
Small Hydro	214	0	0	0	0	0
TOTAL	**242,000**	**2,630**	**13,400**	**2,510**	**33,500**	**3,920**

Table IX-6 compares statewide criteria pollutant emissions in 2020 for the 20 percent RPS to those for the proposed RES, high load forecast. This table shows that the proposed RES will reduce emissions of all criteria pollutants by five to 10 percent. By comparing Tables IX-4 and IX-5, it can be seen that most of the pollutant reductions result from decreased generation by existing natural gas plants.

Tables IX-7 and IX-8 show statewide criteria pollutant emissions in 2020 for the low load forecast for the 20 percent RPS and proposed RES, respectively.

Table IX-6
2020 Statewide Criteria Pollutant Emissions and Emission Reductions from Electricity Generation:
20 Percent RPS vs. Proposed 33 Percent RES, High Load Forecast

Scenario	Emissions and Emission Reductions (tons/yr)				
	ROG	NO_x	SO_x	CO	$PM_{2.5}$
20% RPS	2,920	14,700	2,650	35,100	4,230
Proposed 33% RES	2,630	13,400	2,510	33,500	3,920
Emission Reductions	**290**	**1,300**	**140**	**1,600**	**310**
Percent Reduction	**10%**	**9%**	**5%**	**5%**	**7%**

Table IX-7
2020 Statewide Criteria Pollutant Emissions from Electricity Generation:
20 Percent RPS, Low Load Forecast

Resource	CA Power Generation (GWh)	Emissions (tons/yr)				
		ROG	NO_x	SO_x	CO	$PM_{2.5}$
EXISTING:						
Traditional Sources						
Natural Gas Peaker	7,570	265	1,510	76	1,510	227
Natural Gas Baseload	37,400	748	1,870	187	1,870	748
Nuclear	32,600	0	0	0	0	0
Large Hydro	40,000	0	0	0	0	0
Coal	1,300	13	2,530	778	4,600	324
Renewable Sources						
Wind	5,720	0	0	0	0	0
Solar Thermal	724	11	72	1	15	11
Solar PV	0	0	0	0	0	0
Geothermal	12,900	194	19	6	5	194
Solid-Fuel Biomass	5,720	572	5,150	1,140	21,500	1,140
Landfill/Digester Gas	0	0	0	0	0	0
Small Hydro	3,730	0	0	0	0	0
NEW:						
Traditional Sources						
Natural Gas Peaker	8,520	85	426	85	852	256
Natural Gas Baseload	20,900	209	730	104	1,040	313
Renewable Sources						
Wind	2,730	0	0	0	0	0
Solar Thermal	1,820	9	4	1	5	5
Solar PV	999	0	0	0	0	0
Geothermal	6,490	6	10	0	1	65
Solid-Fuel Biomass	1,150	6	231	58	115	231
Landfill/Digester Gas	1,310	262	196	0	1,240	20
Small Hydro	214	0	0	0	0	0
TOTAL	**192,000**	**2,380**	**12,700**	**2,440**	**32,700**	**3,540**

Table IX-8
2020 Statewide Criteria Pollutant Emissions from Electricity Generation: Proposed 33 Percent RES, Low Load Forecast

Resource	CA Power Generation (GWh)	Emissions (tons/yr)				
		ROG	NO_x	SO_x	CO	$PM_{2.5}$
EXISTING:						
Traditional Sources						
Natural Gas Peaker	5,870	205	1,170	59	1,170	176
Natural Gas Baseload	27,700	554	1,380	138	1,380	554
Nuclear	32,600	0	0	0	0	0
Large Hydro	40,000	0	0	0	0	0
Coal	1,300	13	2,530	778	4,600	324
Renewable Sources						
Wind	5,720	0	0	0	0	0
Solar Thermal	724	11	72	1	15	11
Solar PV	0	0	0	0	0	0
Geothermal	12,900	194	19	6	5	194
Solid-Fuel Biomass	5,720	572	5,150	1,140	21,500	1,140
Landfill/Digester Gas	0	0	0	0	0	0
Small Hydro	3,730	0	0	0	0	0
NEW:		0	0	0	0	0
Traditional Sources						
Natural Gas Peaker	4,620	46	231	46	462	139
Natural Gas Baseload	20,900	209	730	104	1,040	313
Renewable Sources						
Wind	17,300	0	0	0	0	0
Solar Thermal	13,000	65	26	6	33	39
Solar PV	3,170	0	0	0	0	0
Geothermal	6,490	6	10	0	1	65
Solid-Fuel Biomass	1,150	6	231	58	115	231
Landfill/Digester Gas	1,310	262	196	0	1,240	20
Small Hydro	214	0	0	0	0	0
TOTAL	**204,000**	**2,140**	**11,700**	**2,340**	**31,500**	**3,210**

Table IX-9 compares statewide criteria pollutant emissions in 2020 for the 20 percent RPS to those for the proposed RES, low load forecast. This table shows that, similar to the high load case, the proposed RES will reduce all criteria pollutant emissions by four to 10 percent. An evaluation of the out-of-state criteria pollutant impacts for the proposed RES can be found in Appendix E.

Table IX-9
2020 Statewide Criteria Pollutant Emissions and Emission Reductions from Electricity Generation:
20 Percent RPS vs. Proposed 33 Percent RES, Low Load Forecast

Scenario	Emissions and Emission Reductions (tons/yr)				
	ROG	NO_x	SO_x	CO	$PM_{2.5}$
20% RPS	2,380	12,700	2,440	32,700	3,540
Proposed 33% RES	2,140	11,700	2,340	31,500	3,210
Emission Reductions	**240**	**1,000**	**100**	**1,200**	**330**
Percent Reduction	**10%**	**8%**	**4%**	**4%**	**9%**

3. Permitting and Other Requirements

Under State law, districts have the primary responsibility for controlling air pollution from non-vehicular sources. Each district has a program to address new stationary sources of air pollution. These programs are referred to as new source review (NSR) programs. NSR programs provide mechanisms to: (1) reduce emission increases up-front through the use of clean technology, and (2) achieve a "no net increase" in emissions of nonattainment pollutants or their precursors for all new or modified sources that exceed particular emission thresholds. This is accomplished through two major requirements in district NSR rules: best available control technology (BACT) and offsets. The districts also develop rules to reduce emissions from specific sources and govern the overall permitting process. Also, the districts enforce their local rules and prepare local air quality plans to achieve ambient air quality standards. CEC must also certify new electricity generation plants that generate 50 or more megawatts.

In addition to meeting district NSR rules, new electricity generation plants must meet CEQA requirements as part of the permitting process. As these electricity plants are large industrial facilities, an environmental impact report (EIR) must be prepared. To comply with CEQA requirements, the EIR must identify any significant environmental impacts, identify feasible alternatives, and incorporate feasible mitigation measures to minimize the significant adverse environmental impacts identified in the environmental impacts analysis. CEQA requires that no project, which may have significant adverse environmental impacts, be adopted as originally proposed if feasible alternatives or mitigation measures exist. However, a project may be approved if specific overriding considerations outweigh the potential adverse consequences of any unmitigated impacts.

The emission estimates used for this air quality impact analysis reflect the use of the cleanest energy production technologies and air pollution control technologies. Even the use of the cleanest technologies can result in unmitigated emissions. The emission estimates do not account for emission offsets that may be purchased to comply with NSR programs because these offsets are project-specific. Emission offsets may lead to emission reductions at locations other than the project site, providing benefits to local communities that are not adjacent to a project site.

4. Regional Criteria Pollutant Emissions

In this section, ARB staff used outputs from the RES Calculator to illustrate a range of potential new renewable resource mixes that could provide power to the grid in 2020 based on the 20 percent RPS and proposed RES scenarios, respectively. These scenarios identify potential types and regional locations of new renewable resources. Some localized air impacts may occur in areas where new renewable generation facilities are sited. However, renewable generation is expected to displace existing fossil-fuel generation and reduce the need for new fossil-fuel generation, resulting in net air quality benefits to impacted communities. The criteria pollutant and toxic emissions associated with new renewable generation facilities will be subject to district permitting and CEQA requirements.

The results of this analysis indicate that the 20 percent RPS accounts for most of the criteria pollutant emissions from new renewable resources and these emissions are distributed throughout the State. All of the criteria pollutant emissions from the proposed RES would occur in the Mojave Desert, Salton Sea, San Francisco Bay, and South Coast Air Basins. The proposed RES accounts for about 11 percent of the criteria pollutant emissions from new renewable resources in the high load forecast, and six percent of the criteria pollutant emissions from new renewable resources in the low load forecast.

Tables IX-10 and IX-11 show the energy production and regional criteria pollutant emissions in 2020 for new renewable resources for the high load forecast. Table IX-10 shows that about 40 percent of the total energy production from new renewable resources in the 20 percent RPS high load forecast is concentrated away from populated areas in the Mojave Desert and Salton Sea Air Basins.[5,6] The CREZ zones (see Appendix B) located in the Mojave Desert Air Basin are Barstow, Inyokern, Iron Mountain, Kramer, Mountain Pass, Needles, Pisgah, Riverside East, San Bernardino-Baker, San Bernardino - Lucerne, Tehachapi, Twentynine Palms, and Victorville. The CREZ zones in the Salton Sea Air Basin are Imperial East, Imperial North, and Imperial South. The remaining 60 percent of the new renewable resources are distributed throughout the State, based on procurements from IOU and POU contracts. No specific location is provided for these renewables in the RES Calculator output. These renewables are assumed to be distributed generation that does not require additional major transmission lines (see results within the RES Calculator as described in Chapter V).

Table IX-10
Regional Criteria Pollutant Emissions in 2020 for New Renewable Resources
20 Percent RPS, High Load

Regional Renewable Resources	Energy Production (GWh)	Emissions (tons/yr)				
		ROG	NO_x	SO_x	CO	$PM_{2.5}$
Mojave Desert						
Wind	7,430	0	0	0	0	0
Solar Thermal	1,040	5	2	0	3	3
Solar PV	98	0	0	0	0	0
Subtotal	***8,570***	***5***	***2***	***0***	***3***	***3***
Salton Sea						
Geothermal	48	0	0	0	0	1
Subtotal	***48***	***0***	***0***	***0***	***0***	***1***
Distributed Statewide						
Wind	193	0	0	0	0	0
Solar Thermal	1,460	8	3	1	4	4
Solar PV	966	0	0	0	0	0
Geothermal	6,490	7	10	0	1	65
Solid-Fuel Biomass	1,150	6	231	58	115	231
Landfill/Digester Gas	1,310	262	196	0	1,240	20
Small Hydro	214	0	0	0	0	0
Subtotal	***11,800***	***283***	***440***	***59***	***1,360***	***320***
Regional Total	**8,610**	**5**	**2**	**0**	**3**	**4**
STATEWIDE TOTAL	**20,400**	**288**	**442**	**59**	**1,360**	**324**

Table IX-11 shows the additional energy production and criteria pollutant emissions from new renewable resources needed to meet the increment between the 20 percent RPS and the proposed RES, under the high load forecast. The additional energy production and criteria pollutant emissions would occur in the Mojave Desert, Salton Sea, San Francisco Bay, and South Coast Air Basins. The CREZ zone located in the San Francisco Bay Air Basin is Solano. The CREZ zones located in the South Coast Air Basin are Fairmont and Palm Springs. The proposed RES accounts for approximately 11 percent of the criteria pollutant emissions from new renewables in the high load forecast. Since Table IX-11 shows the increment between the 20 percent RPS and proposed RES, the regional total is the same as the statewide total.

Table IX-11
Regional Criteria Pollutant Emissions in 2020 for New Renewable Resources
Proposed 33 Percent RES, High Load

Regional Renewable Resources	Energy Production (GWh)	Emissions (tons/yr)				
		ROG	NO_x	SO_x	CO	$PM_{2.5}$
Mojave Desert						
Wind	9,870	0	0	0	0	0
Solar Thermal	12,100	60	24.3	5	30	36
Solar PV	1,870	0	0	0	0	0
Subtotal	***23,900***	***60***	***24.3***	***5***	***30***	***36***
Salton Sea						
Geothermal	11,600	11	17	1	1	116
Subtotal	***11,600***	***11***	***17***	***1***	***1***	***116***
San Francisco Bay						
Wind	3,190	0	0	0	0	0
Subtotal	***3,190***	***0***	***0***	***0***	***0***	***0***
South Coast						
Wind	4,010	0	0	0	0	0
Solar Thermal	225	1	0.4	0	1	1
Solar PV	504	0	0	0	0	0
Subtotal	***4,740***	***1***	***0.4***	***0***	***1***	***1***
Regional Total	**43,400**	**72**	**42**	**6**	**32**	**153**

Table IX-12 shows the total criteria pollutant emissions in 2020 for new renewable resources for the 20 percent RPS and the proposed RES in the Mojave Desert, Salton Sea, San Francisco Bay, and South Coast Air Basins for the high load forecast. Table IX-12 shows the criteria pollutant emissions from new renewable resources in these regions are primarily from the proposed RES.

Table IX-12
Cumulative Impact in 2020 for New Renewable Resources
20 Percent RPS and Proposed 33 Percent RES, High Load

Scenario	Energy Production (GWh)	Emissions (tons/yr)				
		ROG	NO_x	SO_x	CO	$PM_{2.5}$
20% RPS	8,610	5	2	0	3	4
Proposed 33% RES	43,400	72	42	6	32	153
Cumulative Regional Impact[a]	**52,000**	**77**	**44**	**6**	**35**	**157**

[a] Cumulative Regional Impact = 20 Percent RPS + Proposed 33 Percent RES

Tables IX-13 and IX-14 show the energy production and regional criteria pollutant emissions in 2020 for new renewable resources for the low load forecast. Table IX-13 shows that about 20 percent of the total energy production from new renewable resources in the 20 percent RPS low load forecast is concentrated away from populated

areas in the Mojave Desert Air Basin. The remaining 80 percent of the new renewable resources are distributed throughout the State.

Table IX-13 also shows that the criteria pollutant emissions in the Mojave Desert Air Basin for new renewable resources are negligible. ARB staff assumes no operational emissions for wind, solar PV, and small hydro renewable resources (see Appendix D). The majority of the emissions for new renewable resources are distributed throughout the State.

Table IX-13
Regional Criteria Pollutant Emissions in 2020 for New Renewable Resources
20 Percent RPS, Low Load

Regional Renewable Resources	Energy Production (GWh)	Emissions (tons/yr)				
		ROG	NO_x	SO_x	CO	$PM_{2.5}$
Mojave Desert						
Wind	2,540	0	0	0	0	0
Solar Thermal	354	2	0.7	0	0.9	1
Solar PV	34	0	0	0	0	0
Subtotal	***2,920***	***2***	***1***	***0***	***1***	***1***
Distributed Statewide						
Wind	193	0	0	0	0	0
Solar Thermal	1,460	7	3	1	4	4
Solar PV	966	0	0	0	0	0
Geothermal	6,490	6	10	0	1	65
Solid-Fuel Biomass	1,150	6	231	58	115	231
Landfill/Digester Gas	1,310	262	196	0	1,240	20
Small Hydro	214	0	0	0	0	0
Subtotal	***11,800***	***281***	***440***	***59***	***1,360***	***320***
Regional Total	**2,920**	**2**	**1**	**0**	**1**	**1**
STATEWIDE TOTAL	**14,700**	**283**	**441**	**59**	**1,360**	**321**

Table IX-14 shows the additional energy production and criteria pollutant emissions from new renewable resources needed to meet the increment between the 20 percent RPS and the proposed RES, under the low load forecast. The additional energy production and criteria pollutant emissions would occur in the Mojave Desert, San Francisco Bay, and South Coast Air Basins. The proposed RES accounts for approximately six percent of the criteria pollutant emissions from new renewables in the low load forecast. Since Table IX-14 shows the increment between the 20 percent RPS and the proposed RES, the regional total is the same as the statewide total.

Table IX-14
Regional Criteria Pollutant Emissions in 2020 for New Renewable Resources
Proposed 33 Percent RES, Low Load

Regional Renewable Resources	Energy Production (GWh)	Emissions (tons/yr)				
		ROG	NO_x	SO_x	CO	$PM_{2.5}$
Mojave Desert						
Wind	9,870	0	0	0	0	0
Solar Thermal	11,300	57	23	5	28	34
Solar PV	1,710	0	0	0	0	0
Subtotal	***22,900***	***57***	***23***	***5***	***28***	***34***
San Francisco Bay						
Wind	3,190	0	0	0	0	0
Subtotal	***3,190***	***0***	***0***	***0***	***0***	***0***
South Coast						
Wind	4,010	0	0	0	0	0
Solar Thermal	225	1	0	0	1	1
Solar PV	504	0	0	0	0	0
Subtotal	***4,740***	***1***	***0***	***0***	***1***	***1***
Regional Total	**30,800**	**58**	**23**	**5**	**29**	**35**

Table IX-15 shows the total criteria pollutant emissions in 2020 for new renewable resources in the Mojave Desert, San Francisco Bay, and South Coast Air Basins for the low load forecast. Table IX-15 shows the criteria pollutant emissions from new renewable resources in these regions are primarily from the proposed RES.

Table IX-15
Cumulative Impact in 2020 for New Renewable Resources
20 Percent RPS and Proposed 33 Percent RES, Low Load

Scenario	Energy Production (GWh)	Emissions (tons/yr)				
		ROG	NO_x	SO_x	CO	$PM_{2.5}$
20% RPS	2,920	2	1	0	1	1
Proposed 33% RES	30,800	58	23	5	29	35
Cumulative Regional Impact	**33,800**	**60**	**24**	**5**	**30**	**36**

5. Toxic Air Contaminants

Staff anticipates that the proposed RES regulation would result in a decrease in the statewide emission of toxic air contaminants (TACs) as fossil-fuel power generation is displaced by renewable generation. Renewable power generation from wind, solar PV, and small hydro resources have no direct toxic emissions. However, TACs are emitted when power is generated from natural gas, coal, solid-fuel biomass, and landfill/digester gas. The ten most common TACs associated with these facilities are acetaldehyde, benzene, 1,3-butadiene, carbon tetrachloride, hexavalent chromium, para-dichlorobenzenes, formaldehyde, methylene chloride and perchloroethylene. However, power plants are not major stationary sources of these TACs. No additional power generation in California from solid-fuel biomass and landfill/digester gas is predicted under the possible compliance scenarios for the proposed RES.

New and modified sources of TAC emissions are subject to district review to evaluate potential public exposure and health risk, mitigate potentially significant health risks resulting from these exposures, and decrease health risk by improving the level of emissions control. Further public protection is provided through the Air Toxics "Hot Spots" Information and Assessment Act,[7] which requires stationary sources, such as power generating plants, to report the types and quantities of certain substances routinely released into the air. Formaldehyde and benzene are among the substances that are reportable. The goals of the Air Toxics "Hot Spots" Act are to collect emission data, identify facilities having localized impacts, ascertain health risks, notify nearby residents of significant risks, and reduce those significant risks to acceptable levels. Refer to Section E (Impacted Communities) for a discussion of diesel PM emissions associated with solid-fuel biomass generation.

D. Public Health Impacts

This section describes the emission impacts of criteria and toxic air pollutants on statewide public health associated with the operation of renewable electricity generation facilities. Electricity generated by various renewable resource technologies is evaluated for potential public health impacts.

1. Regulatory Background

ARB has many programs and plans that are designed to identify and mitigate public exposure to air pollutants in communities throughout the State. ARB has identified low income communities and sensitive populations highly impacted by air pollution as a priority when addressing criteria pollutants and toxic air contaminants. Within this environmental evaluation, ARB staff has quantified, where possible, the potential changes to criteria (NO_x and $PM_{2.5}$) and toxic air pollutants that would result from implementation of the proposed RES.

2. Health Impacts of PM

In conjunction with GHG reductions from the implementation of the proposed RES, the level of $PM_{2.5}$ is expected to be reduced. These reductions, in turn, should proposed lead to reductions in the incidence of a variety of associated adverse health impacts. We base this conclusion on the evidence provided by the epidemiologic studies described in U.S. EPA's "Integrated Science Assessment for Particulate Matter"[8] and "Quantitative Health Risk Assessment for Particulate Matter, Second External Review Draft."[9]

The U.S. EPA Integrated Science Assessment concluded that long-term $PM_{2.5}$ exposure can "causally" exacerbate chronic cardiovascular disease, leading to mortality and hospitalizations related to cardiovascular diseases. The review also concluded that long-term $PM_{2.5}$ exposure has a "likely causal" relationship with exacerbation of chronic respiratory diseases, leading to mortality and hospitalization. Moreover, $PM_{2.5}$ exposure has been associated with a number of other health endpoints that could adversely impact public health in California. For example, reports in the scientific literature have associated $PM_{2.5}$ exposure with other adverse health effects such as myocardial infarction (heart attack), chronic bronchitis, acute bronchitis, emergency room visits for asthma, asthma symptoms, other respiratory symptoms, low birth weight, preterm birth, reduced lung function growth in children, minor restricted activity days and work loss days.

The implementation of the RES should also result in a reduction of NO_x emissions, which are a precursor to nitrates, a secondary PM formed in the atmosphere. This should result in further reduction in ambient $PM_{2.5}$ levels beyond the direct $PM_{2.5}$ reductions noted above. Secondary $PM_{2.5}$ represents a portion of total $PM_{2.5}$, and a fraction of the health impacts associated with total $PM_{2.5}$ can be attributed to secondary $PM_{2.5}$. Hence, reduced exposure to both primary and secondary $PM_{2.5}$ is anticipated to result in a reduction in the statewide number of premature deaths and hospitalizations due to exacerbated respiratory and cardiovascular disease, as well as other adverse health effects.

E. Impacted Communities

The following section discusses the potential impact of the proposed RES on existing natural gas electrical generation located within or near impacted communities.

1. Impacted Areas

ARB staff used the impacted areas identified for ARB's Carl Moyer (Moyer) program pursuant to AB 1390 (Firebaugh, 2001) to identify impacted communities.[10] Based on the location of these impacted communities, staff worked with districts to identify facilities generating electricity that are either located within or near these impacted communities.

AB 1390 established environmental justice requirements for the Moyer program. This law required districts with a population of more than one million inhabitants to allocate at least 50 percent of their Moyer funding for the benefit of low-income communities and communities that are disproportionately affected by air pollution. The districts affected by the legislation identified these areas within their jurisdictions. ARB staff used these designations developed for the Moyer program for the Bay Area Air Quality Management District (BAAQMD), San Joaquin Valley Air Pollution Control District (SJVAPCD), San Diego Air Pollution Control District (SDAPCD), and South Coast Air Quality Management District (SCAQMD) to identify the impacted communities.

2. Existing Natural Gas Generation

a. Introduction

The addition of renewable generation to satisfy the 33 percent requirement will reduce the overall operation, and hence emissions, of California's natural gas fleet, but also alter their usage in ways that could affect emissions at some locations and at certain hours. As discussed earlier, this fleet is generally composed of boilers, CCCTs, and CTs. Additionally, the natural gas generation fleet includes some cogeneration facilities and engine-based facilities. Cogeneration facilities are typically operated to satisfy the electricity or heat requirements for a host facility and do not provide electricity to the grid. Hence, the proposed RES is not expected to significantly affect the operation of cogeneration facilities. Finally, there are only a few engine-based generation facilities. Because of the small number of these types of generators, staff will not further discuss the impact of the proposed RES on this category.

The boilers are the oldest combustion based generation in the State. Their operation has largely been displaced by more efficient CCCTs and CTs. However, these boilers still operate a significant amount of time during the summer, primarily due to operational limitation[b] and local reliability requirements. Consequently, the overall capacity factor[c] for boilers is low—in 2008, the capacity factor for these boilers was 15 percent.

CTs are mainly operated to provide peak generation. As discussed below, these units typically operate a few hundred hours to a thousand hours a year, primarily in the summer months.

CCCTs provide the majority of the load-following generation. Consequently, these units operate throughout the year and have a capacity factor between 50 and 60 percent. The generation from renewable generation will largely displace generation provided today by CCCTs.

[b] Boilers need a significant amount of time for start up and shutdown. Consequently, many units operate throughout the summer—operating at minimum generation during the overnight hours and increasing operation during the day.
[c] Capacity factor is defined as the actual hours operated divided by 8,760 hours, the number of hours in a year.

b. Impact of RES on Existing Natural Gas Generating Fleet

The renewable generation that would result from the implementation of the proposed RES will largely displace generation used for load-following. As indicated above, the increased renewable generation is likely to replace generation provided by CCCTs. Consequently, while the overall generation from CCCTs will be reduced by renewable generation, the reduced production will not necessarily result in many CCCTs shutting down. Instead, most existing CCCTs are likely to operate at a lower capacity factor. Additionally, it is unclear how much of the renewable generation will displace generation from the existing fleet or delay the construction of new CCCTs. CAISO, as part of their 33 percent integration study, is evaluating the impact of integrating renewable generation on the existing generation fleet. As part of this research, CAISO will also examine the need for additional generation for the 20 percent RPS and the proposed RES. As indicated earlier, this study is not expected to be completed until the end of 2010.

c. Backing-up Wind and Solar Generation

As discussed earlier, wind and solar generation are variable generation. Both wind and solar generation are affected by the availability of the resource and changing weather conditions. This generation must be firmed and shaped so that it can be incorporated into the grid. Firming and shaping refer to using additional power to make the variable generation constant and packaging the variable generation so that it can be imported into the transmission system.

For wind and solar generation occurring out-of-state and being delivered to California, the shaping and firming currently occurs largely outside of California and the associated emissions would occur outside California. If the energy comes from the Pacific Northwest, hydroelectric generation is typically used for shaping and firming. In this case, there are no additional emissions associated with the generation. Wind and solar generation occurring within the State would be shaped and firmed with available local generation, which will be mainly CCCTs and CTs. There is some potential for increased pumped storage and other changes in in-state hydro operations. However, the bulk of the in-state emissions from backing-up variable generation will be from the State's fleet of CCCTs and CTs.

To the extent that wind and solar are not providing the expected generation, CCCTs and to a lesser extent CTs, will need to increase generation to replace the missing generation from wind and solar. Consequently, during these instances, the potential emissions benefit attributed to wind and solar generation would not be fully realized. These emissions would not be considered emissions that are the result of implementing the RES, but are emission reductions that are not realized because of the variable generation of wind and solar resources.

For example, a CCCT that operates today at 600 MW may operate at 400 MW when renewable generation provides 33 percent of the total retail generation. When the

variable generation that is expected to provide 50 MW, but only provides 40 MW for a given period, then the CCCT will need to increase operation to 410 MW to provide backup power for the variable generation. Based on this example, for the period of time needed for this backup generation, the benefit is reduced by 10 MW, but the CCCT is still operating at a much lower level as a result of the increased renewable generation. The emission benefit for that period is decreased by the amount of GHG emissions associated with the 10 MW increase.

As discussed in Chapter V, there are periods when wind and solar generation experience sharp increases and decreases in generation. In these situations, CTs and occasionally hydroelectric generation will be needed to balance the generation with load. This will be needed at sunrise and sunset when both wind and solar generation generally experience sharp increased and decreases, respectively. The operation of the CTs in this manner is directly attributable to the additional variable renewable generation being added to the grid. The emission increases attributed to the operation of the CTs in this manner would be allocated to the RPS program and to the proposed RES program. The next section discusses the current operation of various natural gas generation resources located within or near impacted communities.

d. Existing CCCTs and CTs

Staff evaluated potential air impacts from additional natural gas generation that may be needed to shape and firm new generation from variable renewable energy resources such as wind and solar. Staff evaluated existing natural gas-fueled facilities located within or near impacted communities within the jurisdiction of the BAAQMD, SJVAPCD, and SCAQMD. The types of facilities evaluated include CCCTs, CTs, cogeneration, and engine peaking facilities. Overall, staff evaluated 28 facilities within these three air districts—three facilities located in BAAQMD, 15 facilities located in SJVAPCD, and 10 facilities located in SCAQMD. Specific information for each facility is listed in Appendix D. Table IX-18 summarizes the information for the 28 facilities evaluated.

Table IX-18
Operating Data for Natural Gas Generation Located Within BAAQMD, SJVAPCD, and SCAQMD

	CCCT	CT	Cogeneration	Engine
Total Units at the 28 Facilities	14	37	4	1
Range of Capacity Factor (%)	4 - 74	0 – 61	2 - 95	NA
Average Capacity Factor (%)	31	13	39	50

The capacity factors shown above are based on operating information for 2008, the most recent information available for all three air districts. CCCT, CT, and cogeneration facilities all exhibit a wide range of capacity factors for 2008. (Since there is only one

example of an engine peaking plant, staff did not include a discussion of this facility.) Because CCCTs provide load-following generation and cogeneration facilities provide baseload generation, both CCCTs and cogeneration facilities are expected to operate more than CTs. For the facilities being reviewed, the CCCTs and cogeneration facilities are operating between two to thee times more than the CTs.

The average capacity factor for CTs is particularly low, with 22 of the 37 CTs, or 60 percent of the CTs reviewed, operating at a capacity factor that is less than the average capacity factor for CTs. The average capacity factor for CTs represents an average of 600 hours of operation per year. These values are consistent with the CTs being used to provide power for a few hours a day during the peak summer season. Because these units are subject to air district permitting requirements, many of the units have operational restrictions that typically limit operation to 50 percent of capacity. For example, a facility can operate 8,760 hours annually, but the permit may restrict the facility to 4,500 hours of operation annually. A facility that operates 450 hours in 2008 would have a permitted capacity of ten percent.

In addition to operational limits, nearly all units evaluated were required to install best available control technology to reduce NO_x, VOC, and CO emissions. Nearly all generation facilities were required to achieve a NO_x emission limit of 2.5 to 3 ppmv at 15 percent O_2—a level requiring NOx reduction of 95 percent or more. The few CTs that were allowed to satisfy less stringent standards are subject to limited hours of operation on an annual basis. The applicable air district permits limit these units to 400 hours per year. Before these units can operate more hours, the operators would need to satisfy more stringent NO_x limits. Consequently, the criteria pollutant emissions from the natural gas-fueled generating fleet are well controlled.

Staff also reviewed available operational information for these units for 2007 to evaluate the variability in their operation from year to year. Table IX-19 compares the hours of operation in 2008 to 2007, by each major category, and shows the variable nature of these types of generation (i.e., the operation varies regionally and year to year). For example, the table shows that CTs in the BAAQMD operated 50 percent less in 2008 than they operated in 2007—in other words, the CTs operated more in 2007 than in 2008. This variation will depend upon the amount of hydroelectric generation available and the amount of air conditioning needed during a hot summer day (i.e., a hotter than usual summer will mean a higher load demand and more operation of CTs).

Table IX-19
2008 Facility Operation Versus 2007 Facility Operation

Type of Generation	Percent Change in Electrical Generation in 2008 Versus 2007			Overall for Projects Reviewed
	BAAQMD	SCAQMD	SJVAPCD	
CT	-50 percent	+30 percent	-2 percent	+11 percent
CCCT		+50 percent	-3 percent	+25 percent
Cogeneration			+5 percent	
Engine			+70 percent	

While CT operation was generally higher overall in 2008 than in 2007 for the facilities reviewed, about half of the individual facilities operated more in 2007 than in 2008. Additionally, on a regional basis, from 2007 to 2008, CT operation increased significantly for CTs located within SCAQMD, but CTs located in SJVAPCD operated at similar levels for both years. This illustrates the difficulty in forecasting the amount of generation a specific facility may provide in a given year.

The CCCTs located in SCAQMD operated 50 percent more in 2008 than in 2007. This shows that CCCTs are not immune to significant changes in operation from year to year.

e. Summary

The proposed RES would add a significant amount of variable renewable generation to the grid whose availability would be based on daily and seasonal fluctuations in sunlight or wind patterns. The electricity from all renewable generation, including the variable generation, will largely displace generation used in load-following applications. In California, CCCTs are the main units used for load-following applications. Consequently, there should be a reduction in emissions at many of the CCCTs, including some CCCTs located at or near impacted communities.

The variable renewable generation will need to be backed-up. The backup is needed when the renewable generation is not providing the expected generation or when there is a sharp increase or decrease in generation. In the case where not enough generation is being provided by the variable generation, the CCCT may need to operate at a higher level for a short duration. Because the renewable generation has already reduced the operation of the CCCT, the increased operation to provide backup generation will result in less electricity being displaced. In no case will the increased operation to makeup the shortfall in generation from the variable resource result in the CCCT operating at the same level prior to the influx of renewable generation. This increased operation will reduce the benefit that can be derived from variable resources.

Conversely, if the proposed RES is enacted, CTs are likely needed to compensate for these potential sharp changes in generation. A portion of these potential emission increases can be attributed to the proposed RES.

For the existing fleet of CTs, the potential increases in operation would be allowed by air district permits. Staff expects the overall increase in operation for this function to be modest. Additionally, because the fleet of CTs within California is both large in number and spread throughout the State, staff expects that the operational increases and associated increases in air emissions would be a small amount for any one facility.

As discussed above, CAISO is evaluating the need for additional resources to support the integration of 33 percent renewables. At this time, it's unclear if additional CTs will be necessary to fully integrate the variable renewable generation resulting from the proposed RES. In addition, the net change in emissions from CTs and CCCTs will be better understood with the completion of the CAISO simulations in 2010. Staff notes that many tools are currently being developed that could lower the emissions impact from integrating renewable generation. This includes improvements in renewable energy forecast error that could allow for less "back-up" power needs, operational control of the variable generation resources in particular hours to lessen the requirements on the natural gas plants, and the integration of storage technologies, and demand response.

3. New Solid-Fuel Biomass Facility

Staff estimated criteria pollutant emissions from a new 50 megawatt (MW) solid-fuel biomass facility. This facility would generate about 425 GWh per year of renewable power. Biomass power generation is considered to be baseload generation that does not require fossil-fuel backup power. Table IX-18 summarizes the air pollution impacts from such a facility. In addition to power generation emissions, this table shows the annual diesel truck emissions from hauling feedstock to the facility. The diesel truck emissions estimates assume a 20-ton truck capacity, average fleet truck emissions in 2020, and 80 miles per round trip. Appendix D shows the details of this analysis.

Table IX-18
Estimated Criteria Pollutant Emissions in 2020
Solid-Fuel Biomass Facility (50 MW Capacity)

Source	Emissions (tons/yr)				
	ROG	NO_x	SO_x	CO	$PM_{2.5}$
Operating Emissions (425 GWh)	2	85	21	43	85
Diesel Trucks Emissions	2	30	1	13	1
Total Emissions	**4**	**115**	**22**	**56**	**86**

Depending on the pollutant, this analysis shows that a new 50 MW solid-fuel biomass plant would emit criteria pollutants, ranging from four tons per year of ROG to 115 tons per year of NOx. This facility would have to meet BACT and emission offset

requirements from the appropriate district. The district would also conduct an ambient air quality analysis to ensure that any negative air quality impacts from the facility would be minimized.

The solid-fuel biomass generation under the proposed RES is expected to be at the same level as under the 20 percent RPS. Consequently, the proposed RES is not expected to increase emissions from solid-fuel biomass generation.

4. New Natural Gas Peaker Facility

In the second hypothetical case, staff estimated criteria pollutant emissions from a new natural gas peaker at a new or existing facility. In general, these peakers provide additional power supply for load-following generation or backup power for variable renewable generation.

Staff assumed a new 250 MW capacity peaker that would generate about 750 GWh per year, assuming a capacity factor of 35 percent. Table IX-19 shows criteria pollutant emissions from a new peaker would range from about eight tons per year for ROG to 75 tons per year for CO. The new facility would be required to meet all air district requirements, such as BACT and emission offsets, to minimize any negative air quality impacts from the facility. The air district would also conduct an ambient air quality analysis to ensure that any negative air quality impacts from the facility would be minimized.

The proposed RES is not expected to increase emissions from new natural gas peaker facilities. The proposed RES is expected to reduce the need for new natural gas peaker facilities.

Table IX-19
Estimated Criteria Pollutant Emissions in 2020
Additional New Natural Gas Peaker (250 MW Capacity)

Source	Emissions (tons/yr)				
	ROG	NO_x	SO_x	CO	$PM_{2.5}$
Operating Emissions (750 GWh)	8	38	8	75	23

F. Other Environmental Impacts

ARB, in consultation with a contractor (Ascent Environmental), evaluated the non-air environmental impacts associated with the proposed RES. In addition to new renewable generation facilities, new transmission lines will be required to bring electricity from producing zones in remote areas to end users. Distribution lines may also need to be upgraded. In some locations, existing transmission lines connected to fossil fuel power plants may need to be upgraded to maintain system reliability while supporting power supplies from variable renewable resources such as wind and solar. These issues are discussed in Chapter V. The contractor considered the Renewable

Energy Transmission Initiative and other reports to identify potential transmission lines, environmental impacts, and mitigation measures for the installation of new transmission lines in the State. The CEQA analysis for non-air environmental impacts includes land, water, biology, cultural, and visual impacts. In addition, the contractor developed a qualitative analysis of the out-of-state environmental impacts from the proposed RES.

1. Summary of Ascent Environmental Impact Analysis

Because ARB is not responsible for implementation of renewable energy project-specific mitigation and the programmatic analysis does not provide sufficient details to determine project-specific mitigation, there is inherent uncertainty in the degree of mitigation ultimately implemented to reduce the potentially significant impacts. Consequently, the analysis takes the conservative approach in its post-mitigation significance conclusions (i.e., tending to overstate the risk that feasible mitigation may not be sufficient) and discloses, for CEQA compliance purposes, that potentially significant environmental impacts may be unavoidable. It is expected that renewable energy projects will be able to feasibly avoid or mitigate to a less-than-significant level many of these potentially significant impacts as an outcome of their project-specific environmental review processes. The details of the analysis are included in Appendix E.

a. Aesthetics

Depending upon their location, size, and character, development of renewable energy projects necessary for compliance with the 33 percent RES regulation may result in adverse effects on designated scenic vistas, scenic resources, the visual character or quality of sites where renewable energy projects would occur, and could create a new source of substantial light or glare. Implementation of mitigation (A-1 through A-10) may reduce the severity of such impacts, but it is uncertain whether mitigation would be sufficient to reduce potential impacts to less-than-significant levels. Therefore, these impacts would be potentially significant and unavoidable and the project would have a substantial contribution to significant cumulative visual impacts.

b. Biological and Forest Resources

The future development of renewable energy projects under the proposed RES could result in the following: (1) loss of special-status plants and animals due to construction, operation, and maintenance of energy generating structures and transmission lines; (2) placement of fill material into waters of the United States, including wetlands, or removal of riparian or other habitats considered sensitive by resource agencies; (3) loss, degradation, or fragmentation of common habitats. The WECC service area supports a number of native habitats that are important to wildlife. Large areas of native habitat could be substantially reduced or fragmented on a regional scale due to renewable energy development; (4) interfere with wildlife movement or impede the migration of fish populations. These projects could reduce the ability of terrestrial wildlife populations to move unimpeded through an area. In addition, impacts to aquatic

habitat, such as diversion of stream flows, could impede movement of native fishes and aquatic wildlife; (5) conflict with adopted habitat conservation plans, natural communities conservation plans, other conservation plans or other policies to protect natural resources; and (6) loss or conversion of forest lands.

Mitigation C-1 through C-6 addresses the impacts above and applies to both the 20 percent RPS and proposed RES scenarios. Because ARB has no regulatory oversight on the implementation of the mitigation, impacts to biological and forestry resources may not be fully mitigated and, therefore, would remain potentially significant. In addition, some impacts to biological and forest resources may not be feasible to mitigate fully due to the nature of the impact. Therefore, these impacts would be potentially significant and unavoidable and the project would have a substantial contribution to significant cumulative biological and forest resources impacts.

c. Cultural Resources

All new renewable energy projects proposed for construction as part of the proposed RES, no matter their location in-state or out-of-state, would have the potential to result in significant impacts to cultural and paleontological resources depending on their location in proximity to cultural resources and their potential to result in ground disturbance. The types of cultural resources that could potentially be affected with renewable energy facility construction could include, but are not limited to, prehistoric and historical archaeological sites, paleontological resources, historic buildings, structures, or archaeological site associated with agriculture and mining, and heritage landscapes. Properties important to Native American communities and other ethnic groups, including tangible properties possessing intangible traditional cultural values, also may exist. Such resources may occur individually, in groupings of modest size, or in districts. Implementation of mitigation (D-1 through D-10 in Appendix E) may reduce the severity of such impacts, but it is uncertain whether mitigation would be sufficient to reduce potential impacts to less-than-significant levels. Therefore, these impacts would be potentially significant and unavoidable and the project would have a substantial contribution to significant cumulative cultural resources impacts.

d. Geology, Soil, and Mineral Resources

Proposed renewable energy projects located within the identified CREZs would be subject to substantial risk of loss and possible injury or death due to the probable strong seismic ground shaking associated with earthquake activity. This includes the risk of seismic-related ground failure, including liquefaction and in some locations landslides. In addition, it is not known which, if any, of the proposed CREZ renewable energy project areas would require the use of septic tanks or alternative waste water disposal systems. The amount of fine-grained material in the alluvium is not known and can affect its suitability to support such a system. As a result, the risk of impact to the proposed project located within the identified CREZs due to strong seismic ground shaking and unsuitable soils to support septic tanks or alternative waste water disposal systems is considered potentially significant. While Mitigation E-1 in Appendix E is recommended to reduce significant seismic hazard impacts, it is unknown at this time

whether feasible mitigation is available, or if available, if this mitigation would be able to reduce the impact to a less-than-significant level. It is also uncertain if, following the implementation of Mitigation E-3 in Appendix E, suitable areas that would support the installation of septic tanks or alternative waste water disposal systems can be located. Therefore, these impacts would be potentially significant and unavoidable and the project would have a substantial contribution to significant cumulative geology and mineral resources impacts.

All proposed CREZ project areas are susceptible to erosion or loss of top soil, unstable geologic units or soil, and the presence of expansive soils. Without implementation of Mitigation GEO-2 and GEO-3 in Appendix E, this would be a potentially significant impact. However, with implementation of mitigation, the potential impacts would be reduced to less-than-significant levels.

e. Hazard and Hazardous Materials

The risk of impact to the proposed project due to routine transport, use, or disposal of hazardous materials would be less-than-significant for all renewable energy project types under the 20 percent RPS and proposed RES (low and high load forecasts). This is because the proposed renewable energy facilities would generally be located substantial distances from highways, major developments, and other sensitive receptors, and would be required to comply with all appropriate federal, State, and local laws regarding the transportation of hazardous materials. The potential for hazardous emission release within one quarter mile of a school would be a less-than-significant impact under the 20 percent RPS and proposed RES (low and high load forecasts) because no school facilities are located within ¼-mile of any of the proposed CREZs. Similarly, no public or private airports are located within 2 miles of any of the proposed CREZs and no airport land use plans would apply to the CREZs. Therefore, future development of renewable energy projects under the proposed regulation change would result in less-than-significant hazard impacts to schools and airports under the 20 percent RPS and proposed RES (high and low load forecasts).

Implementation of renewable energy projects would result in less-than-significant emergency response plan impacts under the 20 percent RPS and proposed RES (low and high load forecasts) because these projects would be subject to local land use approvals that would ensure the proposed facilities provide adequate emergency response and access to and from the site. In addition, wildland fire risks would be less-than-significant for all renewable energy project types under the 20 percent RPS and proposed RES (low and high load forecasts) because projects would be required to use construction/maintenance equipment with appropriate spark-suppression controls and would be required to provide adequate fire suppression facilities onsite.

The future development of renewable energy projects under the proposed RES could create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment. Although precautions can be taken (refer to Mitigation G-1 in

Appendix E) to ensure that any spilled fuel is properly contained and disposed, the potential still remains for a significant release of hazardous materials into the environment and it is unknown whether mitigation would be available or could feasibly reduce this impact to a less-than-significant level. Therefore, this impact would be potentially significant and unavoidable and the project would have a substantial contribution to significant cumulative visual impacts.

Proposed renewable energy projects located within the identified CREZs are not located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code Section 65962.5[11] and, as a result, would not create a significant hazard to the public or the environment. This would be a less-than-significant impact.

f. Hydrology, Water Quality, and Supply

The specific hydrology, water quality, and supply impacts (i.e., lowering of groundwater levels, stormwater drainage and flooding hazards, construction-related impact to water quality, and long-term operations-related effects to surface and groundwater quality) of the proposed RES cannot be identified with any certainty. Therefore, the renewable energy projects could potentially result in significant environmental impacts. It is unknown whether mitigation would be available or feasible to reduce the impact to a less-than-significant level. As a result, these water supply impacts would remain potentially significant and the project would have a substantial contribution to a significant cumulative impact.

g. Land Use, Planning, and Agriculture

Implementation of the proposed RES would be unlikely to physically divide an existing community. Therefore, this impact is considered less-than-significant. However, implementation of the proposed RES would likely result in conflicts with certain applicable land use plans, policies, or regulations of an agency with jurisdiction over the project adopted for the purpose of avoiding or mitigating an environmental effect. The proposed project could also result in the conversion of farmland to non-agriculture uses. Because ARB has no land use authority, mitigation measures are not available to mitigate these impacts to a less-than-significant level. Compliance with existing land use policies, ordinances, and regulations would serve to minimize this impact and land use impacts would be further addressed for individual projects through the project's CEQA and/or NEPA review. However, because ARB cannot guarantee proposed renewable energy projects would be consistent with any applicable land use policies, ordinances, or regulations, these impacts are considered significant and unavoidable and the project would have a substantial contribution to a significant cumulative land use, planning, and agricultural impact.

Implementation of the proposed RES would likely result in conflicts with existing zoning for agricultural uses or Williamson Act contracts. The areas identified by the RETI as most suitable for alternative energy development contain land zoned for agricultural uses and that are currently under Williamson Act contracts. Although mitigation

measures, such as Best Management Practices, may be available to reduce such impacts, ARB cannot guarantee their implementation or effectiveness. Therefore, impacts related to conflicts with existing zoning for agricultural uses or Williamson Act contracts would remain significant and unavoidable and the project's contribution to this significant cumulative impact would be cumulatively considerable.

h. Noise

The specific noise (and vibration) impacts related to future development of renewable energy projects under the proposed RES cannot be identified with any certainty because the specific location, type, and number of renewable energy projects constructed in State or out-of-state is not known at this time. However, nearby sensitive receptors could be located within the distances modeled in the analysis (see Chapter III.J., 'Noise' I Appendix E) that are correlated with typical noise (and vibration) standards and recommended-acceptance levels. In addition, these projects could potentially result in exposure of new workers to noise levels in excess of standards for which it is unknown whether mitigation would be available to reduce the impact to a less-than-significant level. Thus, implementation of new renewable energy projects could result in substantial increases in ambient noise levels and expose persons to or generate noise levels in excess of applicable standards. While mitigation is recommended to reduce significant impacts, it is unknown at this time whether feasible mitigation is available, or if available, if this mitigation would be able to reduce the impact to a less-than-significant level. Therefore, for purposes of this analysis, this impact is concluded to be significant and unavoidable and the project would have a substantial contribution to a potentially significant and unavoidable cumulative impact.

i. Recreation

The construction of substantial additional renewable generation and transmission capacity in California and the Western U.S. would occur as a result of the proposed RES, with much of it expected to be on public land. The potential exists to directly disrupt, indirectly interfere with use of, or reduce the recreation resource qualities and availability of public lands. Also, new renewable energy generation and transmission facilities could directly disrupt, indirectly interfere with use of, or reduce the recreational resource qualities of private land occupied by or located near renewable energy projects. While the specific location of projects cannot be identified with any certainty, the magnitude of increased renewable energy facilities could result in significant recreational impacts. This impact is considered potentially significant for all renewable energy types under the proposed RES (high and low load forecasts). While mitigation is recommended to reduce significant impacts, it is unknown at this time whether feasible mitigation is available, or if available, if this mitigation would be able to reduce the impact to a less-than-significant level. Therefore, for purposes of this analysis, this impact is concluded to be significant and unavoidable and the project would have a substantial contribution to a potentially significant and unavoidable cumulative impact.

j. Public Services, Utilities, and Solid Waste

Because the specific public services and utilities (i.e., police, fire, emergency response, electricity, natural gas, water supply, wastewater capacity), impacts of the proposed RES cannot be identified with any certainty, these projects could potentially result in potentially significant environmental impacts. While mitigation L-1 and L-2 in Appendix E have been recommended to reduce the impact, it is unknown whether this mitigation could feasibly reduce the impact to a less-than-significant level. Therefore, the project's public services and utilities impacts would be significant and unavoidable and the project would have a substantial contribution to a significant cumulative impact.

Renewable energy projects that would be served by a municipal wastewater service provider or would operate individual septic systems or on-site wastewater treatment plants would not be anticipated to exceed wastewater treatment requirements because the treatment facilities would operate under approved wastewater treatment requirements and would be monitored by appropriate regulatory agencies to ensure compliance. In addition, all renewable energy projects would be provided solid waste from an appropriately certified local provider that would haul the solid waste to an approved and permitted disposal facility. None of the renewable energy projects (in State or out-of-state) would be anticipated to result in significant impacts related to a violation of solid waste regulations.

k. Transportation/Traffic

Although the specific location, type, and number of renewable energy projects constructed in-State or out-of-state is not known at this time, project construction and operational activities could conflict with applicable programs, plans, ordinances, or policies (i.e., performance standards, congestion management); result in a change in air traffic patterns; substantially increase hazards due to a design feature; or result in inadequate emergency access. Consequently, because the specific transportation and traffic impacts of the proposed RES cannot be identified with any certainty, and the renewable energy projects could potentially result in significant environmental impacts for which it is unknown whether mitigation would be available to reduce the impact to a less-than-significant level, this impact is considered potentially significant and the project would have a substantial contribution to a significant cumulative impact.

REFERENCES

[1] California Environmental Quality Act. Public Resources Code section 21000 et seq, http://www.leginfo.ca.gov/cgi-bin/calawquery?codesection=prc&codebody=&hits=20

[2] National Environmental Policy Act of 1969. Public Law 91-190, 42 U.S.C., http://ceq.hss.doe.gov/nepa/regs/nepa/nepaeqia.htm

[3] California Energy Commission, 2009. 2009 Integrated Energy Policy Report (Pages 39-56), http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CTF.PDF

[4] ARB, 2008. Climate Change Scoping Plan (Pages 27-67), http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf

[5] ARB, 2006. Quality Assurance Air Monitoring Site Information Interactive Map, http://www.arb.ca.gov/qaweb/mapdemo/map_module.php

[6] Black & Veatch, 2008. CREZ Map, http://www.energy.ca.gov/reti/documents/maps/RETI_Resources_v4.pdf

[7] ARB, 2010. AB 2588 Air Toxics "Hot Spots" Program, http://www.arb.ca.gov/ab2588/ab2588.htm

[8] United States Environmental Protection Agency, 2009. Integrated Science Assessment for Particulate Matter (External Review Draft), http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=201805

[9] United States Environmental Protection Agency, 2010. Quantitative Health Risk Assessment for Particulate Matter, Second External Review Draft, http://www.epa.gov/ttnnaaqs/standards/pm/data/20100209RA2ndExternalReviewDraft.pdf

[10] ARB. Carl Moyer Program Environmental Justice Areas in the "Big Five" Districts.

[11] California Department of Toxic Sustances Control, 2007. DTSC's Hazardous Waste and Substances Site List – Site Cleanup (Cortese List), http://www.dtsc.ca.gov/SiteCleanup/Cortese_List.cfm

X. ECONOMIC IMPACTS

A. Summary of the Economic Impacts

This section describes the cost impacts from the incremental increase in renewable electricity from 20 percent RPS to 33 percent RES for a high and a low load demand scenario. Three models were used for this analysis. The RES Calculator created by Energy and Environmental.Economics, Incorporated (E3), a consulting firm, was used to estimate a possible resource mix and cost of electricity in 2020. The Bill Impact Calculator (BIC) was used to estimate the potential monthly bill impacts of the proposed RES on residential and small business IOU customers. The Environmental-Dynamic Revenue Analysis Model (EDRAM) was used to estimate the macroeconomic impacts of the proposed RES on the Statewide economy including impacts on State output, domestic product, personal income, and employment. These analyses are presented in 2008 dollars and focus on the impacts of the proposed RES regulation in 2020.

The estimated incremental annualized cost of electricity for meeting the proposed 33 percent RES in 2020 is between $2.4 billion and $2.6 billion. The methodology used to estimate this cost in 2020 is consistent with the methodology used in the CPUC's *33 Percent Renewables Portfolio Standard Implementation Analysis Preliminary Results.*[1] However, this analysis done for the proposed RES estimates a lower cost due to the structure of the proposed regulation (i.e., unlimited unbundled RECs) as well as updated renewable generation costs. This is a conservative cost estimate because it assumes that renewable technology costs and performance do not change over time. As newer, better performing technologies come to the market and as demand increases for these new technologies, the costs should decrease over time.

The ARB does not oversee or have the authority to set energy prices. However, while working closely with the CPUC and the IOUs, staff was able to estimate the impact of a 33 percent RES using a Bill Impact Calculator (BIC). The BIC estimates the impact of the proposed RES on both residential and small commercial customer monthly bills. ARB staff estimates that residential rate payers will experience a possible increase in monthly electricity bills between three and ten percent in 2020, depending on electricity usage.

ARB staff also used the BIC to estimate monthly bill impacts for small commercial customers. On average, small businesses may experience a monthly bill increase of about six percent in 2020. This estimate is based on current electricity usage and does not take into account any future energy efficiency improvements.

Staff estimates that the proposed regulation will shift capital from the conventional electricity sector to the construction, manufacturing, and fuel extraction sectors. This results in increased output and employment in these industry sectors. Overall, given the size of the California economy the proposed RES will have a very small, slightly negative impact on the State's economy. Key economic indicators, such as gross State product and employment, show less than a 0.2 percent impact in 2020.

Implementation of the proposed RES will start in 2012. However, no new positions are expected to be added in the early years of the program due to recordkeeping programs already in place for RPS. Once record keeping and enforcement begin for the proposed RES in 2015, it is estimated that a total of eight positions will be needed for monitoring and enforcement at the ARB and CEC, while the CPUC will need no additional resources. This results in a total annual cost of about $1.4 million for additional positions.

B. Legal Requirements

Section 11346.3 of the Government Code requires State agencies to assess the potential for adverse economic impacts on California business enterprises and individuals when proposing to adopt or amend any administrative regulation. The assessment is required to include a consideration of the impact of the proposed regulation on California jobs, business expansion, elimination or creation, and the ability of California businesses to compete with businesses in other states.

Also, State agencies are required to estimate the cost or savings to any State or local agency and school district in accordance with instructions adopted by the Department of Finance (DOF). The estimate is required to include any non-discretionary cost or savings to local agencies and the cost or savings in federal funding to the State.

Finally, Health and Safety Code section 57005 requires the ARB to perform an economic impact analysis of submitted alternatives to a proposed regulation before adopting any major regulation. A major regulation is defined as a regulation that will have a potential cost to California business enterprises in an amount exceeding ten million dollars in any single year. The RES rule is considered a major regulation by this definition.

C. Cost Estimation

The main tool for estimating the cost of the proposed RES is a calculator developed by E3. E3 used the calculator to estimate costs of different scenarios. These scenarios illustrate a range of possible renewable resource mixes that could provide 33 percent renewable power to the California grid in 2020. The RES Calculator and the scenarios are briefly presented in this chapter. Further discussion is included in Chapter V and Appendix B.

1. Renewable Electricity Standard Calculator

The cost of implementing the proposed RES was estimated using the RES Calculator. The RES Calculator is an update of a similar calculator used for the CPUC's 33 percent RPS Implementation Analysis.[1] It was updated to include the most recently available data and to capture some of the regulatory differences between the RPS and the proposed RES.

As explained in Chapter V, the RES Calculator estimates the amount of electricity used to meet demand in 2020, as well as the amount and type of renewable energy needed to meet a renewable energy goal in 2020.

As part of this analysis, the RES Calculator also provides an estimation of the incremental cost of the proposed RES. The incremental costs are estimated by first assessing the renewable mix and costs necessary to meet the current 20 percent RPS in 2020, and then comparing it to the renewable mix and costs that could be used to meet the proposed 33 percent RES in 2020. The cost of the proposed RES is the difference between costs of reaching the existing 20 percent RPS requirements and the 33 percent renewable electricity standard. The cost estimated by the RES Calculator includes the revenues from electricity users needed to cover all costs of generating and delivering additional renewable electricity to retail customers.

2. Proposed Renewable Electricity Standard Scenarios

The costs are estimated for two possible scenarios. The first scenario assumes only the 20 percent RPS in 2020, or the business as usual scenario, and serves as a baseline. The other scenario is based on the proposed RES regulation. The details of these scenarios can be found in Chapter V.

Each scenario was analyzed under two different load-demand conditions. The first, a high load scenario, approximates a case in which some combined heat and power (CHP) and solar distributed generation (solar DG) are incorporated into the load forecast for 2020. However, none of the load reductions attributable to the energy efficiency, enhanced solar DG, and CHP measures specified in the Scoping Plan are included. The high load demand is approximately 301,000 gigawatt hours (GWh) in 2020. This demand represents the retail sales or end use load, which is less than the total generation needed due to transmission and other losses.

The second load scenario is a low load scenario which incorporates full implementation of the Scoping Plan electricity sector measures, as well as the embedded values found in the high load scenario. For the low load scenario, energy efficiency reduces the total load by approximately 22,000 GWh, CHP reduces the load by approximately 14,000 GWh, and solar DG reduces the load by approximately 2,000 GWh. These load reductions result in a total load demand of approximately 263,000 GWh in 2020. As with the high load, these numbers are the retail sales load.

The high and low load 20 percent RPS scenarios formed the basis for estimating the incremental costs of the proposed 33 percent RES regulation.

3. Costs

The RES Calculator accounts for eight cost categories. The categories are listed below.

1. Existing Transmission and Distribution Costs
2. Existing Generation Fixed Costs
3. Existing Generation Variable Costs
4. New Conventional Fixed Costs
5. Existing and New Conventional Variable Costs
6. Incremental Demand Response Cost
7. New Renewables Build
8. New Transmission for Renewables

Cost categories one through three estimate the costs associated with existing electricity transmission, distribution, and generation. Since these costs are associated with electricity already being generated and distributed they are the same for the 20 percent RPS and 33 percent proposed RES cost projections for 2020.

Cost categories four and five estimate the fixed and variable costs associated with new conventional energy needed to meet increased demand in 2020. These costs are based on forecasted natural gas prices, which are highly volatile and may be very different from forecasted values. This cost will be higher for the high load scenario. Despite the increase in renewable electricity generation as a result of the proposed RES, new conventional generation will also be needed as demand increases in the future.

In the low load scenario, incremental costs are incorporated for the demand-side programs that reduce loads. These costs are reflected in cost category six, incremental demand response cost. These include incremental energy efficiency efforts, the California Solar Initiative, combined heat-and-power, and demand response. Costs are incorporated both for the utility (administrative costs and incentives) and for the customer. Utility costs are added to the 2020 revenue requirement, while customer costs are tracked separately.

Categories seven and eight are estimates of the revenue required for new renewable generation and transmission. As a result of the proposed RES, new renewable resources and transmission lines will need to be built to meet the increased demand for renewables. These categories estimate the costs associated with the new renewable build out to meet the proposed RES in 2020.

The resulting costs for the scenarios analyzed are shown in Table X-1. Each of the four scenarios' (high and low load 20 percent RPS and high and low load 33 percent RES) renewable electricity requirements are estimated to be met with a different amount and mix of renewable resources. These amounts and mixes were presented in Chapter V Tables V-10 and V-11. Each scenario has a different cost associated with it. The revenue requirement for the 20 percent RPS and the proposed 33 percent RES is a function of the load demand, the amount of renewable generation required, the renewable resource mix, the location of the resources, and transmission required, among other factors.

Table X-1
Revenue Requirement for Electricity in 2020 (in Millions of 2008 $)

	20 % RPS		33 % RES		Increment	
	High	Low	High	Low	High	Low
Existing Transmission and Distribution Costs	$20,100	$19,300	$20,100	$19,300	$0	$0
Existing Generation Fixed Costs	$8,500	$8,500	$8,500	$8,500	$0	$0
New Conventional Fixed Costs	$4,200	$2,600	$3,200	$1,700	$(1,000)	$(800)
Existing and New Conventional Variable Costs	$10,200	$7,600	$8,500	$6,200	$(1,700)	$(1,400)
Incremental Demand Response Cost	$0	$2,300	$0	$2,300	$0	$0
New Renewables Build	$2,900	$2,300	$7,500	$6,200	$4,700	$3,900
New Transmission for Renewables	$160	$50	$890	$730	$730	$670
Total Revenue Requirement	$46,100	$42,600	$48,700	$45,000	$2,600	$2,400
Average Retail Rate ($/KWh)	$0.15	$0.16	$0.16	$0.17	$0.01	$0.01

The incremental cost impact of the proposed RES regulation over the business as usual (20 percent RPS) in 2020 is $2.6 billion for the high load case and almost $2.4 billion for the low load case. This is the incremental Statewide cost of electricity in 2020 for all regulated parties to meet the proposed 33 percent RES. There is only a $200 million difference between the total cost of reaching 33 percent renewables in 2020 for the high and low load scenarios because load difference in 2020 between the two scenarios is about 38,000 GWh.

These numbers were divided by the total kilowatt hour (kWh) load being served in 2020 to find the average retail rate impact. The incremental average retail rate impact for the high and low load case is $0.01 per kWh. The actual impact on residential and

commercial rate payer bills will vary by utility and usage tier. A further discussion of these rate impacts can be found later in this chapter.

The revenue requirement, or total cost of electricity, is an estimate for the year 2020. These costs, however, are only an estimate. They are dependent on the inputs and assumptions made in the RES Calculator. The Calculator uses planning-level data for technology cost performance rather than contract prices associated with any particular project. Also, it is assumed that renewable technology costs and performance do not change over time. Another factor that can affect these estimates is the price of natural gas. Natural gas prices are highly volatile and may be very different from forecasted values.

4. Federal Incentives

Currently, there are federal policies that incentivize the development and generation of renewable electricity. The RES Calculator assumes that existing federal tax incentives will still be in place in 2020. Biomass, geothermal, and small hydro power receive a production tax credit (PTC) of $0.01 per kWh (in 2008 dollars), while biogas and wind resources receive a PTC of $0.02 per kWh. Solar PV and solar thermal resources receive an investment tax credit of 30 percent, though the RES Calculator assumes that only 95 percent of the capital cost will be eligible to receive that credit.

5. Potential Cost Impact of a Cap and Trade Program

A federal or state cap and trade program could potentially have some effect on the net cost of the proposed RES. A cap and trade program would place a price or value on GHG emissions. Fossil fuel generators would be required to obtain (through purchase or from "for free" allocations) GHG emission allowances equivalent to the amount of GHGs they emit while generating electricity. The cost of these GHG allowances would likely be reflected in an increase in the cost of fossil fuel-generated electricity. The proposed RES requires retail sellers of electricity to utilize more renewable energy and as a result they will be procuring less fossil fuel-generated electricity. The RES Calculator currently reflects the fuels cost savings that utilities will realize under the proposed RES, but does not include any savings that might occur if GHG allowance costs are included in the cost of fossil fuel-generated electricity.

It is possible that a cap and trade program will be in existence well before 2020. However, until the program and the method of making allowances available are better defined, it is impossible to quantify the price effect it would have on fossil fuel generated electricity and the cost savings associated with the proposed RES. ARB staff acknowledges that with a cap and trade in place, there would likely be additional economic benefits from the proposed RES in 2020 that would serve to reduce its net cost to ratepayers. However, due to the uncertainties discussed above, this report does not include an estimate of this potential cost savings in its calculations.

D. Cost-Effectiveness

This section discusses the cost-effectiveness of the proposed regulation. AB 32 requires the Board to consider cost-effectiveness of each GHG control measure it adopts. The values must be expressed in dollars per metric ton of CO_2 equivalent emissions reduced. AB 32 does not specify what should be included in the cost calculations nor does it provide criteria to assess if a regulation is or is not cost-effective.

Staff calculated cost-effectiveness values for the proposed RES. The values were calculated for the year 2020 and were determined by dividing the net compliance cost in 2020 by the total metric tons of CO_2 equivalent emissions expected to be reduced for the same year. (See Chapter IX for a discussion of CO_2 emission reductions.) All costs were calculated in 2008 dollars.

Table X-2 shows the cost-effectiveness of the proposed RES regulation in 2020 for the high and low load scenarios. The cost-effectiveness calculation is based on the incremental CO_2 emission reductions and cost from going from a 20 percent RPS program to the proposed 33 percent RES program. For the high load scenario, there is an estimated reduction in CO_2 equivalent emissions of 13 million metric tons and a total program cost to California of $2.6 billion in the year 2020. The low load scenario cost-effectiveness estimation results from a reduction in CO_2 equivalent emissions of 12 million metric tons and a total program cost of $2.4 billion in the year 2020.

Table X-2
Cost-Effectiveness of Proposed RES in 2020

Dollars per Metric Ton of CO_2 Equivalent Emissions Reduced (2008 $)	
High Load	Low Load
$198	$196

E. Impact on Residential Electricity Bills

The cost to implement the proposed RES will likely be passed on to rate payers in the form of increases in rates and monthly electricity bills. ARB staff worked with staff at the CPUC to estimate the rate impacts of the proposed RES. CPUC staff provided a tool, the RES Bill Impact Calculator (BIC), to estimate bill impacts on Investor Owned Utilities (IOUs) customers. The calculator was used to estimate the percent increase in monthly rates for different rate payer categories in 2020.

1. Methodology for Electricity Bill Impact Assessment

The RES BIC calculates the projected monthly bill impacts from the implementation of the proposed RES in 2020 relative to a baseline bill that assumes no RES implementation. These bill impacts are calculated for residential customers, California Alternative Rates for Energy (CARE) customers (low income residential customers who qualify for the CARE discount), and small commercial customers. The monthly bills are calculated based on the projected revenue requirements from the RES Calculator, while the baseline revenue requirement assumes the high load 20 Percent RPS scenario. The bill impact model was developed collaboratively by the CPUC Energy Division and staff of the IOUs that are regulated by the CPUC. The CPUC approves rate adjustments for IOU customers. This model does not estimate bill impacts for customers of the publically owned utilities (POUs), but staff expects similar bill impacts for their customers.

The bill impacts are calculated in two steps. First, customer bills without the proposed RES are calculated by multiplying the class average rate for each customer class by customer monthly usage. Second, this model calculates a projected 2020 33 percent proposed RES bill adder. The bill impact is the percentage by which the proposed RES bill adder increases the projected customer bill. The 2020 projection is in 2008 dollars.

The BIC was developed to provide results under the high and low load scenarios. The RES Calculator estimates the proposed RES revenue requirements for a high-demand scenario based on the CEC's 2009 IEPR[2] report that includes none of the load reductions attributable to the energy efficiency, enhanced Solar DG and CHP measures specified in the Scoping Plan. The RES Calculator also estimates the proposed RES revenue requirements for a low-demand scenario that incorporates energy efficiency, CHP, and solar DG based load reductions into the 2020 demand forecast based on full implementation of all the Scoping Plan electricity sector measures. The bill impact calculator can be adjusted to produce outputs for either scenario. A more detailed explanation of the BIC methodology is available in Appendix F.

2. Residential Customer Bill Impacts

An increase in electric rates will impact residential utility customers' monthly bills differently depending on energy consumption. Residential rates are tiered, resulting in customers being charged higher rates for higher levels of usage. Using the BIC, staff evaluated the bill impacts on a high, medium, and low usage customer. The cost to implement the program will have a direct effect on the change in customers' monthly bills. Staff estimated the bill impacts for the proposed RES regulation. Because each utility may calculate their rate structures using slightly different methods, a range of monthly bill impacts is shown based on the BIC results. These impacts are show in Table X-3.[a]

[a] Bill Impacts are estimated for the proposed RES compared to the business-as-usual RPS in 2020.

Table X-3
Residential Customer Bill Impacts for 33 Percent RES

	Percent Increase in Monthly Bill	
	High Load	Low Load
Low Usage	3.6 – 4.3	3.2 – 3.9
Moderate Usage	6.1 – 9.0	5.5 – 8.2
High Usage	6.7 – 10.3	6.1 – 9.3

Staff also evaluated the bill impacts on customers enrolled in the CARE program.[b] The CARE program offers income-qualified customers a discount of 20 percent or more off their monthly electric bill. Eligible customers are those whose total household income is at or below the program income limits (see Appendix F). The rate impact calculator was used to estimate the percent rate increase for CARE customers in the three usage tiers. These results are presented in Table X-4.

Table X-4
Residential CARE Customer Bill Impacts for 33 Percent RES

	Percent Increase in Monthly Bill	
	High Load	Low Load
Low Usage	3.7 – 4.1	3.4 – 3.8
Moderate Usage	6.2 – 8.6	5.7 – 7.8
High Usage	6.9 – 9.8	6.3 – 8.9

3. Bill Impacts on Low Income Residential Customers

An important factor to consider is how these monthly bill changes will affect household expenditures. Tables X-5 and X-6 show the average impact of the monthly bill increases as a percent of total expenditures for low income households for the high and

[b] The CARE program is administered by the CPUC, the Low-Income Oversight Board (LIOB), which was established by the Legislature to advise the CPUC on the energy low-income assistance programs of utilities under the PUC's jurisdiction, and the individual IOUs.

low load scenarios. Some customers may fall below the poverty guideline, but do not received CARE rates because they have not enrolled in the program. For this reason, staff has presented bill impacts for both CARE and non-CARE customers.

CARE customers receive a discount on their monthly bill. This discount results in CARE customers having a lower monthly bill, on average, than non-CARE customers. Because their total monthly bill is lower, the percentage impact of the proposed RES on CARE customers' monthly bills will be greater compared to non-CARE customers. For the high load scenario, the average bill impact for a CARE customer is 4.9 percent and for a non-CARE customer is 4.7 percent. For the low load scenario the average bill impact is 4.5 percent for a CARE customer and 4.3 percent for a non-CARE customer.

The income level used for the 100 and 200 percent thresholds is based on a household size of four. A four person household at 100 percent of the poverty guideline has an annual income of $21,200 and a household of four at 200 percent of the poverty guideline has an annual income of $42,400. These calculations are based on the 2008 U.S. Department of Health and Human Services poverty guidelines.[3]

Table X-5
Low Income Residential Customer Bill Impacts of Proposed RES
High Load Scenario

	Income at 100 percent of Poverty Guideline ($21,200/ year)		Income at 200 percent of Poverty Guideline ($42,400/ year)	
	Non-CARE	CARE	Non-CARE	CARE
Average Monthly Bill Impact	$5.10	$4.10	$5.10	$4.10
Share of Income	0.3%	0.2%	0.1%	0.1%

Table X-6
Low Income Residential Customer Bill Impacts of Proposed RES
Low Load Scenario

	Income at 100 percent of Poverty Guideline ($21,200/ year)		Income at 200 percent of Poverty Guideline ($42,400/ year)	
	Non-CARE	CARE	Non-CARE	CARE
Average Monthly Bill Impact	$4.60	$3.70	$4.60	$3.70
Share of Income	0.3%	0.2%	0.1%	0.1%

F. Impact on Small Business

Using the RES Calculator to estimate the revenue requirement in 2020 and the BIC, staff estimated the bill impacts for small businesses. The analysis presented in this section provides a financial assessment of the impacts of the proposed RES on California small businesses. The assessment resulted in the following findings.

- Average monthly electricity bill is expected to increase by about six percent for all California small businesses under the RES proposed regulation.
- Small businesses in almost every industry spend a greater percentage of revenue on electricity costs than large businesses.
- The increase in the electricity bill, if fully passed on, would maximally raise the electricity spending as a percentage of revenue for businesses by less than 0.2 percent (i.e., 2.94 percent x 0.06 percent). This small increase is not expected to have a noticeable impact on competitiveness of small businesses.
- Potential impact on small businesses is likely to be smaller than estimated here. To the extent that small businesses respond to the increase in electricity prices by investing in energy efficient technologies, the impact of any increase in electricity prices is likely to be offset or mitigated by savings from electricity efficiency improvements.

1. Datasets

Under a contract to ARB, Dun and Bradstreet (D&B) created a statistical data model that estimates the portion of revenue that businesses spend on electricity bills. The model is based on all D&B marketing files of approximately 17 million businesses nationwide including over 2.1 million from California. The annual spending on electricity was calculated for affected businesses as follows:

- D&B collected data on monthly electric bills for approximately 628,000 businesses from 18 electrical utility providers nationwide, including two California utilities from April 2007 to March 2008.
- Annual spending on electricity was calculated for these businesses by summing up monthly bills.
- Of the 628,000 businesses nationwide, D&B has revenue data for 210,000 of these businesses.
- Revenue data was available for a greater number of large businesses in the sample. Thus, the sample distribution was adjusted to represent the true universal distribution of the D&B database of 17 million businesses.
- Analysis of the data was provided based on a number of characteristics such as the SIC (Standard Industrial Classification) Code and business size.

The D&B data on electricity spending was used to estimate the impact that electricity price changes may have on small business.

2. Methodology

The increase in electricity spending by California businesses would likely reduce their profitability. Since profitability data were not available for businesses in the D&B database, the change in electricity spending as a percentage of revenue was used as a proxy for the change in business before-tax profitability. Estimating the change in electricity spending by businesses provides a snapshot analysis of the likely impact that electricity costs may have on businesses in California.

The calculations were based on the following assumptions:

- D&B national data was used to calculate business electricity spending as a percentage of revenue; and
- Based on the RES Calculator, the average electricity bill for California businesses will increase by six percent in 2020 relative to business-as-usual.

3. Small Business Competitiveness

According to the D&B study, California businesses spend less than three percent of their revenue on electricity in 2007-2008. The increase in the electricity bill as a result of the proposed RES, if fully passed on, would maximally raise the electricity spending for businesses by less than 0.2 percent (i.e., 2.94 percent x 0.06 percent). This small increase is not expected to have a noticeable impact on the competitiveness of small businesses.

Table X-7 displays the percentage of the revenues spent on electricity for the top 10 California industries compared to the same industries nationwide. For most industries, California businesses spend slightly more on electricity than similar businesses nationwide. However, the majority of the listed business categories are those that serve local markets such as trailer parks and camps, hotels, barbershops, bakeries, etc. Out-of-state businesses cannot serve these local markets. As a result of the proposed RES, California businesses are likely to pass on the bulk of cost increases to consumers in the form of slightly higher prices for their products or services.

Table X-7[c]
List of 10 Industries with Highest Percentage of Revenue Spent on Electricity

SIC	Industry Description	CA Average %	US Average %
8641	Civic and Social Associations	8.6	7.6
7032	Sporting and Recreational Camps	8.2	7.7
7033	Trailer Parks and Campsites	8.2	8.2
7021	Rooming and Boarding Houses	7.4	6.8
7219	Laundry and Garment Services, Nec.	6.9	6.5
7041	Membership-basis Organization Hotels	6.9	6.4
7241	Barber Shops	6.9	6.3
5461	Retail Bakeries	6.9	6.1
8231	Libraries	6.8	5.8
6719	Holding Companies, Nec.	6.6	6.1

A maximum six percent increase in energy cost is unlikely to have a significant adverse impact on California's small businesses. Small businesses, especially those that operate in service industries, would potentially experience a greater increase in their cost of doing business than larger businesses. The potential impact estimated here may be high because small businesses, like any other businesses, are likely to respond to the increase in electricity prices by investing in energy efficient technologies to achieve energy savings. In light of many public incentive programs available, most small businesses should not have difficulties in obtaining the required capital for investment in energy efficient technologies. The savings from electricity efficiency improvements are likely to partially offset or mitigate the impact of any increase in electricity prices.

G. Impact on State Economy

1. Methodology

The model employed to estimate the economic impacts of the proposed RES is a modified version of the Environmental-Dynamic Revenue Analysis Model (EDRAM), a computable general equilibrium (CGE) model. The EDRAM was built by researchers at the University of California, Berkeley. Much of the description of EDRAM is closely adapted from two studies.[4,5]

As a CGE model, EDRAM is designed to capture the fundamental economic relationships between producers, consumers, and government. The model is "computable" because numeric solutions are found using computers rather than solved for algebraically. It is "general" in the sense that all markets and all income flows in the

[c] Nec. stands for not elsewhere classified.

economy are included. It reflects "equilibrium", as prices adjust to equilibrate the demand for and supply of goods, services, and factors of production (labor and capital) of the model. The CGE models are not forecasting models; they are calibrated to reproduce a base year. In the case of EDRAM, the model is constructed to reproduce the economic conditions of calendar year 2003 as this was the latest data available when this version of the model was estimated. For this analysis, economic conditions are grown to project the year 2020. A full description of the EDRAM and its methodology can be found in Appendix F.

2. Statewide Impacts

The RES Calculator was used to estimate the revenue requirement for a mix of renewables sufficient to meet the 33 percent target in 2020 for a high load and a low load scenario. The revenue requirement and resource mix results from the RES Calculator were used as inputs to EDRAM. EDRAM was used to estimate the economic impacts of the proposed RES. This section shows the results of the EDRAM analysis for both the high load and low load scenarios. Supporting tables and additional analysis can be found in Appendix F.

a. Modeling inputs

EDRAM's baseline scenario assumes no or little renewable electricity in 2020. Therefore, in order to estimate the incremental impact of 33 percent RES over the 20 percent RPS, a 20 percent RPS scenario was developed and run in EDRAM and then the 33 percent RES scenario was run. The difference in economic indicators such as gross State product and Statewide employment for these two scenarios provides an estimate of the Statewide economic impacts of the proposed 33 percent RES relative to the currently required 20 percent RPS.

In order for EDRAM to estimate the impacts of RES on the Statewide economy, the economic activity related to the build out of renewables must be assigned to the appropriate economic sectors. The economic sectors most affected by renewable electricity are identified in Table X-8. The economic activity associated with building and operating renewable electricity generation is closely related to the following industrial sectors used in EDRAM: agricultural sector (agriculture), industrial building construction sector (construction), and fabricated structural metal manufacturing sector (manufacturing). For each type of renewable resource, it was estimated what percentage of the money spent on that resource would go to each affected sector. For example, for every $100 spent on generating electricity from solar PV, it was estimated that $35 is spent in the industrial construction sector, and $65 is spent in the metal manufacturing sector. The percentage assumptions for each type of resource were based on literature review.[6,7,8,9,10]

Table X-8
Percent Allocation of Electricity-Generating Expenditure to Relevant EDRAM Sectors

Renewables	Agriculture	Construction	Manufacturing
Solar PV	0%	35%	65%
Solar Thermal	0%	25%	75%
Wind	0%	25%	75%
Geothermal	0%	35%	65%
Landfill/Digester Gas	26%	24%	50%
Solid-Fuel Biomass	27%	23%	50%
Small Hydro (< 30 MW Capacity)	0%	35%	65%
Transmission	0%	25%	75%

Table X-9 shows data from the RES Calculator for the 20 percent RPS in 2020 and 33 percent proposed RES in 2020 scenario runs. This cost and resource mix information is translated into inputs for EDRAM based on resource type and expenditure in 2020.

Table X-9
EDRAM Inputs for 20 percent RPS Baseline and Proposed 33 percent RES
(Billion 2008 $)

Cost Category	High Load Expenditure			Low Load Expenditure		
	20% RPS	33% RES	Change	20% RPS	33% RES	Change
Landfill/ Digester Gas	$0.11	$0.11	$0	$0.11	$0.11	$0
Solid-Fuel Biomass	$1.14	$1.14	$0	$1.14	$1.14	$0
Geothermal	$1.80	$2.97	$1.17	$1.80	$1.80	$0
Small Hydro (< 30 MW Capacity)	$0.50	$0.50	$0	$0.50	$0.50	$0
Solar PV	$0.20	$0.62	$0.42	$0.19	$0.59	$0.41
Solar Thermal	$0.59	$2.65	$2.06	$0.47	$2.51	$2.04
Wind	$1.20	$2.00	$0.81	$0.76	$2.00	$1.24
Total	$5.54	$10.0	$4.46	$4.96	$8.66	$3.69
New Transmission	$0.16	$0.89	$0.73	$0.05	$0.73	$0.67
Gas- Fuel	($1.79)	($2.74)	($0.95)	($1.54)	($2.31)	($0.76)
Gas- Capital, Operation, & Maintenance	($1.64)	($2.76)	($1.12)	($1.48)	($2.31)	($0.83)
Total	$2.26	$5.39	$3.12	$2.0	$4.77	$2.77

The total incremental cost presented in Table X-9, above, and the revenue requirement presented earlier in the chapter both come from the RES Calculator. The revenue requirement is associated with the amount of renewable generation to get from 2008 levels to the 2020 renewable standards. Because there is little renewable energy built into EDRAM, the scenarios are run from zero percent to 20 percent for the baseline scenario and from zero percent to 33 percent for the proposed RES scenario. For this reason, the total incremental cost input for EDRAM is higher than the revenue requirement presented earlier.

Since there is more money being spent in the industry sectors related to renewables, EDRAM assumes there is less money being spent in the sector representing conventional electricity generation. This translates to less spending from the conventional electricity sector to its supply source: California's fossil fuel extraction

sector, mainly natural gas.[d] This change in the transfer of money between sectors results in a change in the macroeconomic indicators of the State's economy between the baseline and 33 percent RES scenario.

b. Results

Once the flow of money through the different economic sectors is assigned, EDRAM can be run. The macroeconomic indicator results derived from running EDRAM, for scenario year 2020 and in 2008 dollars, are summarized below.

Table X-10 shows EDRAM's estimates of the overall net impacts of the proposed RES on California's economy, for the high and low load scenarios. As discussed earlier, staff ran the 20 percent RPS baseline scenario and then the 33 percent RES scenario in EDRAM. The difference between these two scenarios is the incremental impact of the proposed RES.

The macroeconomic indicators in Table X-10 are the State output, gross State product, State personal income, and State employment. State output refers to the total market value of all final and intermediate goods and services produced in the State in a given year. The gross State product is the total market value of all final goods and services produced in California in a given year. It is one component of the total State output. State personal income is the economic indicator that measures the total income of all Californians from all sources in a given year. Finally, State employment refers to the total market demand for laborers or the job positions needed in a given year. Overall, the proposed RES is estimated to have a very small impact on these Statewide economic indicators. As shown in Table X-10, all the economic indicators are impacted by less than 0.2 percent as a result of the proposed RES.

[d] California imports much of its natural gas supply from out of state. It is likely that less demand for natural gas will result in decreased imports, rather than less in-state production, resulting in a small impact on California's fossil fuel extraction sector.

Table X-10
EDRAM Results for the Overall Net Effects of the Proposed RES on California's Economy

	20% RPS		33% RES		Incremental Impact		Percent Impact	
	High	Low	High	Low	High	Low	High	Low
Output (Billion $)	$3779	$3779	$3774	$3775	$-5	$-4	-0.13%	-0.12%
Gross State Product (Billion $)	$2676	$2676	$2671	$2672	$-5	$-4	-0.18%	-0.17%
State Personal Income (Billion $)	$2166	$2166	$2162	$2163	$-4	$-3	-0.17%	-0.16%
Employment (Thousands)	18,394	18,395	18,379	18,381	-15	-14	-0.08%	-0.08%

These results provide insights into the potential range of the economic impacts that the proposed RES could have. The impacts estimated by EDRAM show a very slight reduction in economic growth in 2020. For example, 15,000 people will not lose their jobs in 2020 as a result of the proposed RES. Rather, EDRAM estimates job growth in the year 2020 will be 15,000 jobs less due to this proposed regulation. Given that in the first quarter of 2010 California employment grew, on average, by almost 54,000 jobs per month[11], the impact of the proposed RES on the California economy is very small. Also, it is important to remember that factors such as potential decreases in the cost of renewable resources in the future, will affect this estimation.

In the low and high load scenarios the analysis indicates that the proposed RES will have a small, but negative impact on California's macro indicators. Specifically, the analysis indicates that the economic impacts of the proposed RES are imperceptible given the size of the California economy.

H. Green Job Impacts

EDRAM estimates that job growth will be approximately 15,000 jobs less within California's economy, as a result of the proposed RES. The number includes a shift in jobs from sectors that support fossil fuel generation to sectors that support renewable electricity generation. While there may be decreases in employment in some industry sectors there will also be increased employment in others. This section estimates the increase in green jobs, specifically, resulting from a shift to renewable generation in and out of the State.

The employment impacts of renewable electricity generation have been estimated for several resource types, using different types of models, assumptions, and constraints. Estimating the aggregate employment impact of the proposed RES, therefore, requires

normalization of employment factors across different studies. To evaluate the employment impacts of the proposed regulation, ARB applied normalized RES employment factors drawn from 10 different studies issued by private, public, and non-governmental entities. See Table A-1 in Wei, Patadia & Kammen, 2010.[12] The same renewable energy employment factors are also applied in the Green Jobs Calculator developed by the University of California at Berkeley's Renewable and Appropriate Energy Laboratory.[13]

RES employment factors are expressed in terms of net new permanent jobs created per peak MW of renewable generating capacity added. ARB staff applied normalized RES employment factors to the renewable resource outputs of the RES Calculator, as discussed earlier in this chapter and in Chapter V and Appendix B. High-load growth and low-load growth 20-percent baseline scenarios were compared to high-load and low-load versions of the proposed 33 percent RES scenarios. Net changes in power and energy capacity by renewable resource type were calculated for each of the four cases, and RES employment factors applied:[e]

Table X-11
Permanent Jobs Created per Peak MW of Renewable Resource Added

Resource Type	Jobs Created
Solar PV	1.52
Solar Thermal	0.81
Wind	0.52
Geothermal	1.95
Landfill/Digester Gas	5.35
Solid-Fuel Biomass	1.53
Small Hydro (< 30 MW Capacity)	1.28

Tables X-12 and X-13 present the results of this calculation, projecting net increases of 8,000 to 10,000 permanent green jobs in 2020, depending on the scenario chosen. Where out-of-state renewable resources (including tradable RECs) are permitted, less than five percent of new green job creation occurs outside California.

[e] From Wei, Patadia & Kammen, 2010. Where the study includes multiple job creation factors for a single resource type, the job creation estimates were averaged.

Table X-12
Proposed 33 Percent RES, High Load
2020 Green Jobs Change

	In-State		Out-of-State		Total	
	MW	Jobs	MW	Jobs	MW	Jobs
Solar PV	1,000	1,600	0	0	1,000	1,600
Solar Thermal	4,600	3,700	0	0	4,600	3,700
Wind	3,200	1,700	390	200	3,600	1,900
Geothermal	1,500	2,900	0	0	1,500	2,900
Landfill/ Digester Gas	0	0	0	0	0	0
Solid-Fuel Biomass	0	0	30	50	30	50
Small Hydro (< 30 MW Capacity)	0	0	0	0	0	0
Total	10,400	9,900	420	250	10,800	10,100

Table X-13
Proposed 33 Percent RES, Low Load
2020 Green Jobs Change

	In-State		Out-of-State		Total	
	MW	Jobs	MW	Jobs	MW	Jobs
Solar PV	1,000	1,500	0	0	1,000	1,500
Solar Thermal	4,600	3,700	0	0	4,600	3,700
Wind	4,900	2,500	390	200	5,300	2,700
Geothermal	0	0	0	0	0	0
Landfill/ Digester Gas	0	0	2	10	2	10
Solid-Fuel Biomass	0	0	30	50	30	50
Small Hydro (< 30 MW Capacity)	0	0	10	20	10	20
Total	10,400	7,700	440	280	10,900	8,000

The green job estimates presented here may under-estimate the number of permanent new jobs that will be created under the 33 percent proposed RES because:

- The model used to generate the proposed RES employment factors assumes that every new unit of renewable generating capacity displaces a unit of fossil fuel-based generating capacity. Jobs lost through the assumed displacement of fossil fuel-based capacity have been netted out from the estimate of gross new jobs created by added renewable capacity; and

- The proposed RES employment factors do not include induced employment effects, only direct and indirect job creation. Induced employment impacts occur when the spending of direct and indirect employees causes job creation in the general economy, e.g., non-RES related industry jobs such as teachers or store clerks.

However, the proposed RES employment factors also do not take into account the impact of future technological innovation and learning effects, which may reduce the labor requirements of renewable resources. The employment impact estimates presented here could be refined to take additional assumptions and omissions into account.

Direct employment estimates include jobs created in the design, manufacturing, delivery, construction/installation, project management, and operation and maintenance of the renewable facility under consideration. Indirect employment includes impacts on upstream and downstream suppliers to renewable technology manufacturers.

Direct, short-term employment in construction, installation and manufacturing -initially estimated in job-years per MW - is converted to permanent employment (jobs) by dividing by estimated plant/project lifetime, typically 25 or 40 years.

I. Potential Cost to Local, State, and Federal Agencies

1. Cost to Local Agencies

Many of the POUs are owned by local governments. However, these facilities operate as not-for-profit organizations; thus their compliance costs are included in the total costs of the proposed regulation. Because these facilities recover any costs from electricity ratepayers, local tax payers will not be impacted through fiscal budgets.

2. Cost to State Agencies

Implementation of the proposed RES begins in 2012. However, no new positions are expected to be added in the early years of the program due to recording requirements already in place for RPS. There will be no additional fiscal impacts on the State

government from RES in the current fiscal year or until after the first compliance period in the 2015.

After 2015, additional positions will be needed within the agencies responsible for implementation and enforcement of the proposed regulation- the ARB, CEC and CPUC. The CEC and CPUC will be responsible for monitoring and verification of the POUs and IOUs, respectively. It is estimated that the CEC will need up to six additional positions to monitor the POUs compliance with the proposed RES. Since the CPUC already monitors the implementation of the RPS for the IOUs it is not expected this agency will need any additional positions. The ARB will be responsible for enforcement of the proposed RES and has estimated up to two additional positions will be needed.

It is estimated that a total of up to eight positions will be created within the three State agencies responsible for monitoring and enforcement of the proposed regulation. With funding estimated at $175,000 per position per year, these positions will result in an annual cost of about $1.4 million per year, once enforcement begins in 2015.

REFERENCES

[1] California Public Utilities Commission, 2009. 33% Renewables Portfolio Standard Implementation Analysis Preliminary Results, http://www.cpuc.ca.gov/NR/rdonlyres/1865C207-FEB5-43CF-99EB-A212B78467F6/0/33PercentRPSImplementationAnalysisInterimReport.pdf

[2]California Energy Commission, 2008. 2009 Integrated Energy Policy Report, http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF

[3] California Department of Finance, 1996. Dynamic Revenue Analysis for California. Department of Finance, http://www.dof.ca.gov/HTML/FS_DATA/dyna-rev/dynrev.htm

[4] Berck, P., Golan, E., and Smith, B., 1996. Dynamic Revenue Analysis for California. Department of Finance. http://www.dof.ca.gov/HTML/FS_DATA/dyna-rev/dynrev.htm. Accessed March 8, 2010.

[5] California Energy Commission (Prepared by University of California Berkeley), 2007. Macroeconomic Impacts for the State Alternative-Fuels Plan, http://www.irle.berkeley.edu/vial/publications/alt_fuels07.pdf

[6] Bolinger, Mark, 2009. An Update on U.S. Wind Power Prices and the Factors That Influence Them. Presentation at the WINDPOWER 2009, Chicago, Illinois. Lawrence Berkeley National Laboratory. May 5.

[7] European Wind Energy Association, 2009. The Economics of Wind Energy, http://www.ewea.org/fileadmin/ewea_documents/documents/publications/reports/Economics_of_Wind_Main_Report_FINAL-lr.pdf

[8] Lawrence Berkeley National Laboratory, 2009. Tracking the Sun II: The Installed Cost of Photovoltaics in the U.S. from 1998-2008, http://eetd.lbl.gov/ea/emp/reports/lbnl-2674e.pdf

[9] California Public Utilities Commission, 2009. 33% RPS Implementation Analysis: 33% RPS Calculator , http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/33implementation.htm

[10] National Renewable Energy Laboratory, 2010. Jobs and Economic Development Impact (JEDI) Models, http://www.nrel.gov/analysis/jedi/download.html

[11] United States Department of Labor. Economy at a Glance California, http://www.bls.gov/eag/eag.ca.htm

[12] Wei, M., Patadia, S. & Kammen, D., 2009. Putting renewables and energy efficiency to work: How many jobs can the clean energy industry generate in the U.S.?, http://rael.berkeley.edu/sites/default/files/WeiPatadiaKammen_CleanEnergyJobs_EPolicy2010.pdf

[13] Renewable and Appropriate Energy Laboratory. Green Jobs Calculator- (Technologies and Jobs per MW) worksheet, http://rael.berkeley.edu/greenjobs

XI. ALTERNATIVES ANALYSIS

This chapter provides a description of the analysis performed to evaluate two alternatives to the proposed 33 percent RES regulation (proposed RES). These include a no project alternative that evaluates the impacts of not adopting the proposed RES, and an in-state only alternative that evaluates the use of in-state resources only to fill the incremental difference between 20 and 33 percent renewable energy levels.

A. No Project

In order to evaluate the effect of not adopting the proposed RES, staff considered a no project (or business as usual) alternative in 2020. In effect, the result of a no project alternative is the same as the current 20 percent RPS program in place today. The current results estimated by using the RES Calculator show that under the 20 percent RPS condition, between 24,000 and 30,000 GWh of additional renewable energy will be needed in 2020 (depending on a low or high load condition) to meet the 20 percent RPS requirement. This result is lower than previous results due to inclusion of the current 2009 Integrated Energy Policy Report (IEPR)[a] load demand forecast. The 2009 IEPR predicts about 20,000 GWh less than the 2020 forecast in the 2007 IEPR[b], primarily because of lower expected economic growth in both the near and long-term outlook, and because of increased expectations of savings from energy efficiency. In addition, the results include the use of POU renewable resources that are not mandated under the RPS program, but are currently in use or planned for operation by 2020 as discussed in Chapter V of this report (Technology Assessment).

1. Environmental Analysis

The resulting environmental impacts of the no project alternative are the same as the results provided as part of the 20 percent RPS evaluation specified in Chapter IX (Environmental Impacts).

a. GHG Impacts

There are no GHG emission reductions beyond those provided by the 20 percent RPS from the no project alternative. Therefore, the GHG emission reduction impacts from the no project alternative would be to forego 12 to 13 MMTCO2e per year of GHG reductions that are anticipated to occur from the proposed RES. Details are described in Chapter IX.

---

[a] California Energy Commission, 2009. 2009 Integrated Energy Policy Report, http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF

[b] California Energy Commission, 2007. 2007 Integrated Energy Policy Report, http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CMF.PDF

b. Criteria Pollutant Impacts

There are no criteria pollutant emission reductions from the no project alternative beyond those provided by the 20 percent RPS. Therefore, impacts from the no project alternative would be to forego the criteria pollutant emission reductions that are anticipated to occur from the proposed RES, which are shown in Table XI-1. These results are based on output from the RES Calculator and details of the calculations are described in Chapter IX.

Table XI-1
2020 Statewide Criteria Pollutant Emission Reductions from Electricity Generation: Proposed RES High Load and Low Load

Scenario	Emission Reductions (tons/yr)				
	ROG	NO_x	SO_x	CO	$PM_{2.5}$
Proposed RES, High Load	290	1,300	140	1,600	310
Proposed RES, Low Load	240	1,000	100	1,200	330

c. Non-Air Quality Environmental Impacts

Environmental impacts of the no project alternative are identified and assessed for each technical issue area in Chapter III, Impact Assessment, of Appendix E. In summary, the no project alternative would result in impacts from implementation of the 20 percent RPS program from development of additional wind and solar resources, including potentially significant and unavoidable adverse impacts to: scenic resources, biological resources, cultural resources, land use, noise, and recreation.

2. Economic Impacts

The economic impacts from the no project alternative are presented in Chapter X. For the purpose of the economic analysis, the 20 percent RPS case is used as the business as usual in 2020 and compared to the proposed RES in 2020 to estimate the incremental impact of the proposed RES. The cost of the 20 percent RPS case ranges from $42.6 to $46.1 billion in 2008 dollars, for the low and high load forecasts, respectively. The incremental cost of the proposed RES ranges from $2.4 to $2.6 billion in 2008 dollars, for the low and high load forecasts, respectively. Therefore, the no project alternative would forego the incremental cost of $2.4 to $2.6 billion.

3. Conclusion

The no project alternative does not fulfill AB 32 requirements to maximize GHG reductions, because it foregoes the GHG emission reductions of 12 to 13 MMTCO2e per year. In addition, the no project alternative does not fulfill the directive in Executive Order S-21-09 to adopt a regulation requiring regulated

parties to meet a 33 percent renewable electricity standard by 2020. Therefore, this alternative was rejected.

B. In-State Renewable Generation Only (33 Percent RES Alternative)

As an alternative to the proposed RES, staff considered the alternative that requires all new renewables for the increment between the 20 percent and 33 percent levels to be from in-state generation. This prevents the use of unlimited, undelivered RECs and additional out-of-state renewable resources (beyond the 20 percent RPS) to comply with the proposed RES. The purpose of developing this alternative was to examine an alternative that could maximize the amount of in-state renewable generation and criteria pollutant emission benefits. The analysis was conducted using the same RES Calculator used to develop the 20 percent RPS and proposed RES scenarios, with modifications to eliminate the use of out-of-state renewable resources beyond the 20 percent RPS requirement. The results show the renewable generation in California under the in-state alternative would increase by two to three percent or from 1,300 to 1,500 GWh under the high and low load forecasts, respectively. This difference reflects the additional amount of out-of-state renewable generation that is predicted to be used to meet the proposed RES in 2020.

1. Environmental Analysis

The resulting environmental impacts of the RES alternative are very similar to the results provided as part of the proposed RES evaluation specified in Chapter IX (Environmental Impacts).

a. GHG Impacts

The GHG emission reductions for the in-state alternative are identical to those for the proposed RES, which are 12 $MMTCO_2e$ per year for the low load case, and 13 $MMTCO_2e$ per year for the high load case. Details are in Appendix G1.

b. Criteria Pollutant Impacts

In addition to evaluating the 20 percent RPS and the proposed RES, staff also analyzed changes to statewide criteria pollutant emissions that would accompany implementing the RES alternative. The same method used for the air quality analysis presented in Chapter IX, Sections 1 and 2 are used for the evaluation of the RES alternative. The method is described in detail in Appendix D.2.

The RES Calculator provides estimates of electricity generation in 2020 from in-state and out-of-state resources for the high and low load scenarios. The estimates of electricity generation in 2020 are provided in Tables XI-2 and XI-3 for the high and low load forecasts, respectively. These tables compare electricity generation under the proposed RES to the in-state RES alternative. For the high

and low load forecasts, the tables show very little difference in energy production between the proposed RES and the in-state RES alternative.

Table XI-2
Projected Electricity Production in 2020
High Load Scenario

Resource	Electricity Production (GWh)			
	Proposed RES		33% RES Alternative	
	California	Out of State	California	Out of State
EXISTING:				
Traditional Sources	**125,000**	**72,300**	**125,000**	**71,900**
Natural Gas Peaker	8,420	6,470	8,340	6,410
Natural Gas Baseload	43,200	35,500	42,700	35,100
Nuclear	32,600	8,490	32,600	8,490
Large Hydro	40,000	2,630	40,000	2,630
Coal	1,300	19,300	1,300	19,300
Renewable Sources	**28,800**	**2,470**	**28,800**	**2,470**
Wind	5,720	504	5,720	504
Solar Thermal	724	0	724	0
Solar PV	0	0	0	0
Geothermal	12,900	740	12,900	740
Solid-Fuel Biomass	5,720	536	5,720	536
Landfill/Digester Gas	0	0	0	0
Small Hydro	3,730	688	3,730	688
NEW:				
Traditional Sources	**32,400**	**13,200**	**32,300**	**13,100**
Natural Gas Peaker	11,600	3,190	11,400	3,150
Natural Gas Baseload	20,900	10,000	20,900	9,930
Renewable Sources	**55,200**	**10,900**	**56,500**	**9,570**
Wind	17,300	6,990	18,100	5,860
Solar Thermal	13,800	2,440	14,300	2,440
Solar PV	3,330	22	3,430	22
Geothermal	18,100	680	18,100	680
Solid-Fuel Biomass	1,150	236	1,150	12
Landfill/Digester Gas	1,310	16	1,310	16
Small Hydro	214	543	214	543
TOTAL RENEWABLES	**84,000**	**13,400**	**85,300**	**12,000**
TOTAL	**242,000**	**99,000**	**243,000**	**97,000**

Table XI-3
Projected Electricity Production in 2020
Low Load Scenario

Resource	Electricity Production (GWh)			
	Proposed RES		33% RES Alternative	
	California	Out of State	California	Out of State
EXISTING:				
Traditional Sources	**107,000**	**57,500**	**107,000**	**57,100**
Natural Gas Peaker	5,870	4,480	5,760	4,400
Natural Gas Baseload	27,700	22,600	27,300	22,300
Nuclear	32,600	8,490	32,600	8,490
Large Hydro	40,000	2,630	40,000	2,630
Coal	1,300	19,300	1,300	19,300
Renewable Sources	**28,800**	**2,470**	**28,800**	**2,470**
Wind	5,720	504	5,720	504
Solar Thermal	724	0	724	0
Solar PV	0	0	0	0
Geothermal	12,900	740	12,900	740
Solid-Fuel Biomass	5,720	536	5,720	536
Landfill/Digester Gas	0	0	0	0
Small Hydro	3,730	688	3,730	688
NEW:				
Traditional Sources	**25,500**	**8,980**	**25,100**	**8,840**
Natural Gas Peaker	4,620	2,280	4,260	2,240
Natural Gas Baseload	20,900	6,700	20,900	6,600
Renewable Sources	**42,600**	**10,900**	**44,100**	**9,480**
Wind	17,300	6,990	17,300	5,860
Solar Thermal	13,000	2,440	14,300	2,440
Solar PV	3,170	22	3,420	22
Geothermal	6,490	680	6,490	680
Solid-Fuel Biomass	1,150	236	1,150	0
Landfill/Digester Gas	1,310	16	1,310	0
Small Hydro	214	543	214	478
TOTAL RENEWABLES	**71,400**	**13,400**	**73,000**	**11,900**
TOTAL	**204,000**	**79,800**	**205,000**	**77,800**

Table XI-4 compares the criteria pollutant emissions from the proposed RES and the in-state RES alternative for the high load case. Details are in Appendix G1. This table shows the in-state generation only alternative would increase the benefits by less than one percent for all criteria pollutant emissions.

Table XI-4
2020 Statewide Criteria Pollutant Emissions and Emission Reductions from Electricity Generation: Proposed RES vs. 33 Percent RES Alternative, High Load

Scenario	Emissions and Emission Reductions (tons/yr)				
	ROG	NO_x	SO_x	CO	$PM_{2.5}$
Proposed RES	2,630	13,400	2,510	33,500	3,920
33% RES Alternative	2,620	13,400	2,510	33,500	3,910
Emission Reductions	**10**	**0**	**0**	**0**	**10**
Percent Reduction	**0.4%**	**0%**	**0%**	**0%**	**0.3%**

Table XI-5 compares the criteria pollutant emissions from the proposed RES and the in-state RES alternative for the low load case. Details are in Appendix G1. This table shows the in-state generation only alternative would increase the benefits by less than one percent for all criteria pollutant emissions. Therefore, in both the high and low load cases, there are negligible increases in criteria pollutant benefits.

Table XI-5
2020 Statewide Criteria Pollutant Emissions and Emission Reductions from Electricity Generation: Proposed RES vs. 33 Percent RES Alternative, Low Load

Scenario	Emissions and Emission Reductions (tons/yr)				
	ROG	NO_x	SO_x	CO	$PM_{2.5}$
Proposed RES	2,140	11,700	2,340	31,500	3,210
33% RES Alternative	2,130	11,700	2,330	31,500	3,190
Emission Reductions	**10**	**0**	**10**	**0**	**20**
Percent Reduction	**0.5%**	**0%**	**0.4%**	**0%**	**0.6%**

c. Non-Air Quality Environmental Impacts

Environmental effects of the in-state RES alternative would be substantially similar to the proposed RES and would result in substantially similar impacts. Based on modeling by the RES Calculator, this alternative would result in a five percent increase in wind, a four percent increase in solar thermal, and a three percent increase in solar photovoltaic under the high load scenario, and a 10 percent increase in solar thermal generation and an approximately eight percent increase in solar photovoltaic generation under the low load scenario. Therefore, the incremental in-state alternative would result in an increase in impacts to areas that support solar and wind, primarily the southeast desert areas. The alternative would

consume additional desert lands, resulting in slightly greater direct and indirect impacts to desert species and habitat, scenic qualities, and other desert areas and resources (e.g. recreation areas, communities). Air quality impacts would be similar to the proposed RES, but additional in-state renewable development would result in slightly lower criteria air pollutant emissions.

Because ARB is not responsible for implementation of renewable energy project-specific mitigation and the programmatic analysis does not provide sufficient details to determine project-specific mitigation, there is inherent uncertainty in the degree of mitigation ultimately implemented to reduce the potentially significant impacts. Consequently, the environmental impact analysis takes the conservative approach in its post-mitigation significance conclusions (i.e., tending to overstate the risk that feasible mitigation may not be sufficient) and discloses, for CEQA compliance purposes, that potentially significant environmental impacts may be unavoidable. It is expected that renewable energy projects will be able to feasibly avoid or mitigate to a less-than-significant level many of these potentially significant impacts as an outcome of their project-specific environmental review processes.

2. Economic Impacts

Cost and economic impacts were estimated for the in-state generation RES alternative (described above). The methodologies that were used for the cost and economic impact analysis in Chapter X are applied for these analyses, as well.

a. Cost Impacts

The RES Calculator was used to estimate the incremental cost of the alternative RES over the 20 percent RPS. The methodology for the calculator is described in Chapter V and Appendix B. The cost results of the alternative are presented in Table XI-6.

Table XI-6
33 Percent RES Alternative Revenue Requirement (in Millions of 2008 $)

	20 % RPS		33% RES Alternative		Increment	
	High	Low	High	Low	High	Low
Existing Transmission and Distribution Costs	$20,100	$19,300	$20,100	$19,300	$0	$0
Existing Generation Fixed Costs	$8,500	$8,500	$8,500	$8,500	$0	$0
New Conventional Fixed Costs	$4,200	$2,600	$3,200	$1,700	($1,100)	($900)
Existing and New Conventional Variable Costs	$10,200	$7,600	$8,400	$6,100	($1,800)	($1,500)
Incremental Demand Response Cost	$0	$2,300	$0	$2,300	$0	$0
New Renewables Build	$2,900	$2,300	$7,600	$6,300	$4,800	$4,100
New Transmission for Renewables	$160	$50	$1,200	$770	$1,000	$720
Total Revenue Requirement	$46,100	$42,600	$49,000	$45,100	$2,900	$2,400
Average Retail Rate ($/KWh)	$0.150	$0.160	$0.160	$0.170	$0.010	$0.009

The incremental cost impact of the alternative over the business as usual (20 percent RPS) in 2020 is $2.9 billion for the high load case and almost $2.4 billion for the low load case. These numbers were divided by the total kilowatt hour (kWh) load being served in 2020 to find the average retail rate impact. The incremental average retail rate impact for the high load case is $0.010 per kWh and for the low load case is $0.009 per kWh.

The actual impact on residential and commercial rate payer bills will vary by utility and usage tier. A further discussion of these rate impacts can be found later in this chapter.

Table XI-7 compares the incremental revenue requirement estimated to go from the 20 percent RPS to the proposed 33 percent RES and the incremental revenue requirement estimated to go from the 20 percent RPS to the alternative RES scenario. The revenue required to meet the proposed 33 percent RES is less than the revenue required to meet the RES alternative scenario in both the high and low load cases.

Table XI-7
Difference of Incremental Revenue Requirement for Proposed RES and 33 Percent Alternative (in Millions of 2008 $)

	33 % RES		33% RES Alternative		Difference	
	High	Low	High	Low	High	Low
Existing Transmission and Distribution Costs	$0	$0	$0	$0	$0	$0
Existing Generation Fixed Costs	$0	$0	$0	$0	$0	$0
New Conventional Fixed Costs	($1,000)	($800)	($1,100)	($900)	($30)	($80)
Existing and New Conventional Variable Costs	($1,700)	($1,400)	($1,800)	($1,500)	($70)	($80)
Incremental Demand Response Cost	$0	$0	$0	$0	$0	$0
New Renewables Build	$4,700	$3,900	$4,800	$4,100	$100	$200
New Transmission for Renewables	$700	$700	$1,000	$700	$300	$40
Total Revenue Requirement	$2,600	$2,400	$2,900	$2,400	$300	$70
Average Retail Rate ($/KWh)	$0.009	$0.009	$0.010	$0.009	$0.001	$0.000

b. Cost-Effectiveness

Staff calculated cost-effectiveness values for the alternative. The values were calculated for the year 2020 and were determined by dividing the net compliance cost in 2020 by the total metric tons of CO_2 equivalent emissions expected to be reduced for the same year. See Chapter IX for a discussion of CO_2 emission reductions and Chapter X for further discussion of the cost-effectiveness calculation.

For the high load scenario there is an estimated reduction in CO_2 equivalent emissions of 13 million metric tons and a total program cost to California of $2.9 billion. The low load scenario cost-effectiveness estimation results from a reduction in CO_2 equivalent emissions of 12 million metric tons and a total program cost of $2.4 billion. This results in the cost-effectiveness calculations presented in Table XI-8.

Table XI-8
Cost-Effectiveness of 33 Percent RES Alternative in 2020

Dollars per Metric Ton of CO_2 Equivalent Emissions Reduced (2008 $)	
High Load	Low Load
$220	$201

For both the high and low load scenarios the dollars per metric ton of CO_2 equivalent emissions reduced is lower for the proposed RES compared to the RES alternative. For a discussion of the cost-effectiveness of the proposed RES see Chapter X.

c. Residential Customer Bill Impacts

Residential rates are tiered, resulting in customers being charged higher rates for higher levels of usage. Staff evaluated the monthly bill impacts on a high, medium and low usage customer. Rate payer bill impacts were estimated using the Bill Impact Calculator (BIC) as described in Chapter X. A range of rate payer impacts are presented in Table XI-9 for residential customers.

Table XI-9
Residential Customer Bill Impacts for 33 Percent RES Alternative

	Percent Increase in Monthly Bill	
	High Net Load	Low Net Load
Low Usage	4.0 – 4.9	3.2 – 3.8
Moderate Usage	6.8 – 10.3	5.4 – 7.9
High Usage	7.6 – 11.8	5.9 – 9.1

Staff also evaluated the bill impacts on customers enrolled in the CARE program. The CARE program offers income-qualified customers a discount of 20 percent or more off their monthly electric bill. Eligible customers are those whose total household income is at or below the program income limits (see Appendix F). The rate impact calculator was used to estimate the percent rate increase for CARE customers in the three usage tiers. These results are presented in Table XI-10.

Table XI-10
Residential CARE Customer Bill Impacts for 33 Percent RES Alternative

	Percent Increase in Monthly Bill	
	High Net Load	Low Net Load
Low Usage	4.2 – 4.7	3.3 – 3.7
Moderate Usage	7.0 – 9.8	5.5 – 7.6
High Usage	7.8 – 11.2	6.1 – 8.7

For all usage tiers and load cases the BIC estimates a lower percentage monthly bill impact for the proposed RES compared to the RES alternative. For a full discussion of the bill impacts estimated for the proposed RES see Chapter X.

d. Low Income Residential Customer Bill Impacts

As with the regulation analysis, staff estimated bill impacts as a percentage of income for households with income at 100 percent and 200 percent of the poverty

guideline for the alternative. Tables XI-11 and XI-12 how the average impact of the monthly bill increases as a percent of total expenditures for low income households for the high and low load scenarios. Some customers may fall below the poverty guideline, but do not received CARE rates because they have not enrolled in the program. For this reason staff has presented bill impacts for both CARE and Non-CARE customers.

For the high load scenario the average bill impact for a CARE customer is 5.5 percent and for a Non-CARE customer is 5.3 percent. For the low load scenario the average bill impact is 4.6 percent for a CARE customer and 4.4 percent for a Non-CARE customer. The income level used for the 100 and 200 percent thresholds is based on a household size of four. A four person household at 100 percent of the poverty guideline has an annual income of $21,200 and a household of four at 200 percent of the poverty guideline has an annual income of $42,400. These calculations are based on the 2008 U.S. Department of Health and Human Services poverty guidelines.[c]

Table XI-11
Low Income Residential Customer Bill Impacts of
33 Percent RES Alternative
High Load Scenario

	Income at 100 percent of Poverty Guideline		Income at 200 percent of Poverty Guideline	
	Non-CARE	CARE	Non-CARE	CARE
Average Monthly Bill Impact	$5.70	$4.60	$5.70	$4.60
Share of Income	0.3%	0.3%	0.2%	0.1%

[c] California Department of Finance, 1996. Dynamic Revenue Analysis for California, http://www.dof.ca.gov/HTML/FS_DATA/dyna-rev/dynrev.htm

Table XI-12
Low Income Residential Customer Bill Impacts of
33 Percent RES Alternative
Low Load Scenario

	Income at 100 percent of Poverty Guideline		Income at 200 percent of Poverty Guideline	
	Non-CARE	CARE	Non-CARE	CARE
Average Monthly Bill Impact	$4.80	$3.80	$4.80	$3.80
Share of Income	0.3%	0.2%	0.1%	0.1%

All customer bill impacts are estimated to be less from the proposed RES compared to the RES alternative. This results in the low income residential customer rate impacts as a percentage of income to be less, as well, for all incomes.

e. Small Business Impacts

Using the RES Calculator's estimated revenue requirement in 2020 and the Bill Impact Calculator, staff estimated the rate impacts for small businesses. Staff estimated that for the high and low load-demand conditions, when averaged, there will be approximately a six percent increase in electricity rates for small businesses as a result of the proposed RES in 2020. It was also estimated that for the high and low-load demand conditions, when averaged, there will be approximately a 6.5 percent increase in electricity rates for small businesses in 2020 as a result of the RES alternative that was analyzed. Overall, we expect RES to increase electricity expenditure for average California small businesses by six to 6.5 percent relative to business-as-usual in 2020.

A 6.5 percent increase in electricity cost is unlikely to have a significant adverse impact on California small businesses. Small businesses, especially those that operate in service industries, would potentially experience a greater increase in their cost of doing business than larger businesses. The potential impact estimated here may be high because small businesses, like any other businesses, are likely to respond to the increase in electricity prices by investing in energy efficient technologies to achieve energy savings. In light of many public incentive programs available, most small businesses would not have difficulties in obtaining the required capital for investment in energy efficient technologies. The savings from electricity efficiency improvements are likely to offset or mitigate the impact of any increase in electricity prices

f. Economic Impacts

The model employed to estimate the economic impacts of the proposed RES and its alternatives is a modified version of the Environmental-Dynamic Revenue Analysis Model (EDRAM), a computable general equilibrium (CGE) model. The EDRAM was built by researchers at the University of California, Berkeley.

As with the proposed RES, the revenue requirement and resource mix estimated by the RES Calculator for the RES alternative were used as inputs to EDRAM. EDRAM was then used to estimate the economic impacts of the proposed RES. This section shows the results of the EDRAM analysis for both the high load and low load scenarios. Supporting tables and additional analysis can be found in Appendix G2.

1. Modeling Inputs

The methodology for deriving the inputs to EDRAM from the RES Calculator output is described in Chapter X, with supporting documentation in Appendix E. The same methodology applies for deriving the EDRAM inputs for the RES alternative analysis. Table XI-13 shows data from the RES Calculator for the 20 percent RPS in 2020 and RES alternative in 2020 scenario runs. This cost and resource mix information is translated into inputs for EDRAM based on resource type and expenditure in 2020. Supporting tables and additional analysis can be found in Appendix G2.

Table XI-13
EDRAM Inputs for 20 Percent RPS and 33 Percent RES Alternative
(Billion 2008 $)

Cost Category	High Load Expenditure			Low Load Expenditure		
	20% RPS	33% RES Alternative	Change	20% RPS	33% RES Alternative	Change
Landfill/Digester Gas	$0.11	$0.11	$0.00	$0.11	$0.11	$0.00
Solid-Fuel Biomass	$1.14	$1.14	$0.00	$1.14	$1.14	$0.00
Geothermal	$1.80	$2.97	$1.17	$1.80	$1.80	$0.00
Small Hydro (< 30 MW Capacity)	$0.50	$0.50	$0.00	$0.50	$0.50	$0.00
Solar PV	$0.20	$0.64	$0.44	$0.19	$0.64	$0.45
Solar Thermal	$0.59	$2.74	$2.14	$0.47	$2.73	$2.26
Wind	$1.20	$2.07	$0.87	$0.76	$2.00	$1.24
Total	$5.54	$10.16	$4.62	$4.96	$8.92	$3.95
New Transmission	$0.16	$1.19	$1.03	$0.05	$0.79	$0.72
Gas- Fuel	($1.79)	($2.78)	($0.99)	($1.54)	($2.35)	($0.81)
Gas- Capital, Operation, & Maintenance	($1.64)	($2.79)	($1.15)	($1.48)	($2.39)	($0.91)
Total	$2.26	$5.78	$3.51	$2.00	$4.95	$2.95

The total incremental cost presented in Table XI-13, above, and the revenue requirement presented earlier in the chapter both come from the RES Calculator. The revenue requirement is associated with the amount of renewable generation to get from 2008 levels to the 2020 renewable standards. Because there is little renewable energy built into EDRAM, the scenarios are run from zero percent to 20 percent for the baseline scenario and from zero percent to 33 percent for the proposed RES scenario. For this reason, the total incremental cost input for EDRAM is higher than the revenue requirement presented earlier.

Since there is more money being spent in the industry sectors related to renewables, EDRAM assumes there is less money being spent in the sector representing conventional electricity generation. This translates to less spending from the conventional electricity sector to its supply source: California's fossil fuel

extraction sector, mainly natural gas.[d] This change in the transfer of money between sectors results in a change in the macroeconomic indicators of the state's economy between the baseline and 33 percent RES alternative scenario.

2. Results

As explained in Chapter X and Appendix E, once the flow of money through the different economic sectors is assigned, EDRAM can be run. The macroeconomic indicator results derived from running EDRAM, for scenario year 2020 and in 2008 dollars, are summarized below.

Table XI-14 shows EDRAM's estimates of the overall net impacts of the RES alternative on California's economy, for the high and low load scenarios. Staff ran the 20 percent RPS baseline scenario and then the RES alternative scenario in EDRAM. The difference between these two scenarios is the incremental impact of the RES alternative.

The macroeconomic indicators in Table XI-14 are the State output, gross State product, State personal income, and State employment. State output refers to the total market value of all final and intermediate goods and services produced in the State in a given year. The gross State product is the total market value of all final goods and services produced in California in a given year. It is one component of the total State output. State personal income is the economic indicator that measures the total income of all Californians from all sources in a given year. Finally, State employment refers to the total market demand for laborers or the job positions needed in a given year. Overall, the proposed RES is estimated to have a very small impact on these Statewide economic indicators. As shown in Table X-14, all the economic indicators are impacted by less than 0.25 percent as a result of the proposed RES.

[d] California imports much of its natural gas supply from out of state. It is likely that less demand for natural gas will result in decreased imports, rather than less in-state production, resulting in a small impact on California's fossil fuel extraction sector.

Table XI-14
EDRAM Results for the Overall Net Effects of the 33 Percent RES Alternative on California's Economy

	20% RPS		33% RES Alternative		Incremental Impact		Percent Impact	
	High	Low	High	Low	High	Low	High	Low
Output (Billion $)	$3779	$3779	$3773	$3774	$-6	$-5	-0.15%	-0.12%
Gross State Product (Billion $)	$2676	$2676	$2670	$2671	$-6	$-5	-0.21%	-0.18%
State Personal Income (Billion $)	$2166	$2166	$2161	$2162	$-5	$-4	-0.20%	-0.17%
Employment (Thousands)	$18,394	$18,395	$18,377	$18,380	-17	-15	-0.10%	-0.08%

The macroeconomic model, EDRAM, was applied to estimate the impacts of the RES alternative under both low and high load growth scenarios for the proposed RES and the RES alternative: This provides insights into the potential range of the economic impacts that both scenarios would have. In the low and high load scenarios, the analysis indicates that the proposed RES and the RES alternative will have a small impact on California's macro indicators, with the alternative having a slightly larger negative impact. For a full explanation of the indicators see Chapter X.

Table XI-15 presents a comparison of the estimated economic impacts for the proposed RES and the RES alternative. The RES alternative is estimated to have a slightly larger negative impact on the growth of the Statewide economy in 2020, however it is still very small relative to the overall size of the California economy.

Table XI-15
Comparison of Proposed RES and 33 Percent RES Alternative Incremental Economic Impacts

	33% Proposed RES		33% RES Alternative	
	High	Low	High	Low
Output (Billion $)	$-5	$-4	$-6	$-5
Gross State Product (Billion $)	$-5	$-4	$-6	$-5
State Personal Income (Billion $)	$-4	$-3	$-5	$-4
Employment (Thousands)	-15	-14	-17	-15

g. Green Job Impacts

ARB Staff applied normalized RES employment factors to the renewable resource outputs of the RES Calculator to estimate the employment impacts of the RES alternative. High-load growth and low-load growth 20-percent baseline scenarios were compared to high-load and low-load versions of the 33 percent RES alternative scenarios. Net changes in power and energy capacity by renewable resource type were calculated for each of the four cases, and RES employment factors applied. For a full description of this methodology see Chapter X.

Tables XI-16 and XI-17 present the results of this calculation, projecting net increases of permanent jobs in 2020, for both the high and low load scenarios. The results support the hypothesis that renewable energy resources generate more jobs per unit of energy delivered than comparable fossil-fuel resources.

Table XI-16
33 Percent RES Alternative, High Net Load
2020 Green Jobs Change

	In-State		Out-of-State		Total	
	MW	Jobs	MW	Jobs	MW	Jobs
Solar PV	1,100	1,600	0	0	1,100	1,600
Solar Thermal	4,800	3,900	0	0	4,800	3,900
Wind	3,400	1,800	0	0	3,400	1,800
Geothermal	1,500	2,900	0	0	1,500	2,900
Landfill/Digester Gas	0	0	0	0	0	0
Solid-Fuel Biomass	0	0	0	0	0	0
Small Hydro (< 30 MW Capacity)	0	0	0	0	0	0
Total	10,800	10,200	0	0	10,800	10,200

Table XI-17
33 Percent RES Alternative, Low Net Load
2020 Green Jobs Change

	In-State		Out-of-State		Total	
	MW	Jobs	MW	Jobs	MW	Jobs
Solar PV	0	0	0	0	0	0
Solar Thermal	1,100	1,700	0	0	1,100	1,700
Wind	5,100	4,100	0	0	5,100	4,100
Geothermal	0	0	0	0	0	0
Landfill/Digester Gas	0	0	0	0	0	0
Solid-Fuel Biomass	0	0	0	0	0	0
Small Hydro (< 30 MW Capacity)	4,900	2,500	0	0	4,900	2,500
Total	11,000	8,300	0	0	11,000	8,300

Table XI-18 summarizes the net RES employment impacts of the proposed RES and the RES alternative. The alternative scenario is estimated to create more

green jobs within the state and overall according to this analysis. However, the alternative is more expensive and is estimated to cause a greater decrease in job growth within the state in 2020 than the proposed regulation.

Table XI-18
Estimated Net Job Creation Through 2020

	Proposed 33% RES			33% RES Alternative		
	CA	Non-CA	Total	CA	Non-CA	Total
Low Load Growth	9,900	250	10,100	10,200	0	10,200
High Load Growth	7,700	280	8,000	8,300	0	8,300

3. Conclusion

Although the in-state renewable generation only alternative results in identical GHG emission reductions (and essentially identical criteria pollutant emissions), and is estimated to create more green jobs within the state, it requires more revenue, is less cost-effective, has higher monthly bill impacts for residential customers, has a slightly higher increase in electricity rates for small businesses in 2020, and will have a slightly larger negative impact on California's overall economy. Therefore, because this alternative results in identical GHG emission reductions but costs more than the proposed RES, this alternative was rejected.

This Page Intentionally Left Blank

XII. IMPLEMENTATION AND ENFORCEMENT

This chapter provides an overview of the reporting requirements, monitoring and verification through WREGIS, certification of eligible renewable energy resources, recordkeeping requirements, enforcement provisions, and interagency cooperation for the proposed RES program.

A. Reporting Requirements

The proposed RES program will require all regulated parties to submit to ARB annual progress reports and compliance interval reports to demonstrate compliance with the proposed regulation. All submitted reports must be executed by a responsible official having the authority to sign on behalf of the regulated party and bind the regulated party for all purposes regarding compliance with the proposed regulation.

1. Annual Progress Reports

Each regulated party, except for DWR and WAPA, must prepare and submit annual progress reports. Annual progress reports would be due July 1, 2013, and each year thereafter, and would include the following information.

- Regulated Party Information
  - Entity name, contact name, mailing address, phone number, and email address;
  - Name of responsible official for entity; and
  - Entity WREGIS account identification number.
- RES Annual Progress Information
  - WREGIS certificates retired for reporting year by facility identification number; and
  - Retail sales to end-use customers for reporting year.

2. Achievement Plans

Each regulated party, except for those subject to the partial exemption and DWR and WAPA, must prepare and submit an achievement plan. These plans would be due by July 1, 2012. Achievement plans would include the following information:

- Regulated Party Information
  - Entity name, contact name, mailing address, phone number, and email address;
  - Name of responsible official for entity; and
  - Entity WREGIS account identification number.
- Achievement Plan Information
  - Applicable compliance subsection under section 97004; and

- A plan and procurement strategy sufficient to demonstrate how the regulated party plans to achieve and maintain the 33 percent RES requirement by 2020.

3. Compliance Interval Reports

Each regulated party, except those subject to the partial exemption and DWR and WAPA, must prepare and submit compliance interval reports. Compliance interval reports would be due July 1, 2015, July 1, 2018, July 1, 2020, and each year thereafter. Compliance interval reports would include the following information:

- Entity name, contact name, mailing address, phone number, and email address;
- Name of responsible official for entity;
- Entity WREGIS account identification number;
- The applicable compliance subsection under 97004(a) (b) or (c);
- WREGIS certificates retired from the end of the compliance interval to March 31 of the year following the end of the compliance interval;
- Total number of WREGIS certificates retired between the start of the compliance interval and March 31 of the year following the compliance interval by facility identification number;
- Total retail sales to end-use customers for the compliance interval; and
- RES Obligation for the compliance interval.

In the event that a regulated party's compliance interval report indicates that the RES Obligation was not met, the regulated party would also submit the following:

- Documentation of the shortfall, expressed in MWh; and
- A schedule to meet the shortfall within the current year.

4. Partially Exempt Regulated Parties

Each regulated party partially exempt pursuant to section 97003 shall report to ARB by July 1, 2013, and each July 1st thereafter, its total sales to retail end-use customers for the prior calendar year, in MWh.

5. DWR and WAPA Reports

Each year DWR and WAPA would be required to prepare and submit reports detailing their electrical operations. These reports would be due July 1, 2013, and July 1st of each year thereafter and contain the following information:

- Information Requirements
  - Contact name, mailing address, phone number, and email address; and
  - Name of and contact information for Responsible Official for entity;

- Electricity Procured or Generated
  - For each contract or transaction engaged in for the purchase of electricity, specify the amount of electricity procured or generated, the generator fuel type, and the name and location of the entity or power pool from which the electricity was purchased; and
  - For each owned source used to generate electricity, specify the total amount of electricity generated, the name and location of the generator, and the generator fuel type.

- Electricity Used or Sold
  - Identify the total amount of electricity used to convey, pump, and store water, or to serve individual water delivery contracts;
  - For each contract or transaction engaged in for the sale of electricity to retail end-use customers, specify the total amount of electricity sold, the name and location of the generator or source of sold power, the generator or contract source fuel type, and the name and location of the entity to whom the electricity was sold; and
  - For each contract or transaction engaged in for the sale of electricity to non-retail end-use customers, specify the total amount of electricity sold, the name and location of the generator or source of sold power, the generator or contract source fuel type, and the name and location of the entity to whom the electricity was sold.

B. Monitoring and Verification Requirements

CEC currently requires RPS-certified facilities, retail sellers, procurement entities, and third parties to participate in WREGIS. WREGIS is an independent, renewable energy tracking system implemented for the region covered by the Western Electricity Coordinating Council. WREGIS provides an accounting mechanism to track renewable energy generation from units that register in the system using verifiable data and issues WREGIS Certificates for each reported megawatt-hour of eligible generation[1].

The proposed RES program would also require that all regulated parties register with WREGIS and comply with all WREGIS requirements to generate, track and retire WREGIS Certificates used to demonstrate compliance with the RES obligations.

C. Certification of Eligible Renewable Resources

Under the proposed RES program, an eligible renewable energy resource may be certified by any of the following:

- The CEC as meeting the eligibility requirements for the RPS program;
- The CEC under an interagency agreement with ARB, as meeting eligibility requirements for the RPS program, except as to any delivery requirement;
- The CEC under an interagency agreement with ARB for a RES qualifying POU resource using the criteria of section 97002(a)(18); or

- The Executive Officer, his/her designee, or a third party under contract with ARB, using the same criteria that would be used by the CEC under (2) or (3) above.

Applicants seeking certification of an eligible renewable energy resource under the existing RPS program shall file the application with CEC in accordance with their requirements. CEC does not have statutory authority to certify facilities for POUs (or any entity) that do not meet the statutory requirements for RPS-eligibility. Those applicants seeking certification of an eligible renewable energy resource under the proposed RES program must file the application with the ARB Executive Officer. ARB staff is exploring mechanisms by which ARB would receive the application for non-RPS eligible facilities and enter into an interagency agreement with CEC or a third party contractor to review and make recommendations regarding certification and verification of the resource for eligibility under the proposed RES program.

D. Recordkeeping Requirements

All regulated parties would be required to retain copies of all information and records required by the proposed regulation or necessary for verifying the accuracy of any information required or included in the regulated party's applications or reports required by the proposed regulation for no less than seven years. A regulated party would be required to allow the inspection and duplication of such information and records or provide such information and records within 30 days of a written request received from the Executive Officer or designee.

E. Enforcement

1. Violations

ARB would enforce the proposed RES in cooperation with CEC and CPUC to ensure that all regulated parties are in compliance with the proposed regulation. Injunctive relief; civil and criminal penalties may be assessed for noncompliance with the reporting, recordkeeping, and RECs obligation requirements of the proposed RES program. Violations of the RES program requirements would be considered as a violation involving the release of an air contaminant. Enforcement of the proposed RES regulation would involve the following ARB staff activities:

- Receipt of annual progress reports from the regulated parties;
- Receipt of compliance interval reports from regulated parties;
- Review of the reports for completeness and accuracy;
- Evaluation of data in the compliance interval reports to determine if the regulated party is in compliance with the RES obligation requirements of the regulation;
- Inspections or audits of the regulated parties to verify and validate the information submitted in the reports;
- Preparation and issuance of notices of violation;

- Meeting with violators for the purpose of mutual settlement; and
- Participation in litigation, if necessary.

2. Penalties for Non-Compliance

The proposed regulation contains enforcement provisions that authorize the imposition of penalties and other forms of relief for violations of the reporting, recordkeeping, and RECs obligation requirements of the proposed regulation. The legal authority for imposition of these penalties is summarized below.

Consistent with Health & Safety Code (H&SC) § 38580[2] – a State law enacted by Assembly Bill 32 (AB 32), – the proposed regulation provides that the following remedies are available for a violation of any RES provision:

(1) Civil and criminal penalties under H&SC § 42400 et seq. (Part 4)[3]; and
(2) Injunctive relief under H&SC § 41513[4].

All regulations adopted under the authority of AB 32, are enforced pursuant to H&SC §38580. These provisions provide that enforcement of regulations adopted under AB 32 shall be conducted pursuant to the enforcement provisions set out in Part 4 (and Part 5 which is not applicable here) of the California Clean Air Act, commencing with Health and Safety Code §42400. In addition, AB 32 provides that ARB may also seek injunctive relief. Part 4 provides that violations may be pursued either civilly or criminally. ARB usually pursues violations civilly, reserving its ability to pursue violations criminally for the most egregious offenders, where the imposition of civil penalties did not serve to deter violations or where actual physical harm resulted from the violation.

As a regulation adopted under the authority of AB 32, penalties may be assessed for violations of the proposed RES program requirements pursuant to H&SC § 38580. For violations of RES requirements, each day or portion of a day during which a violation occurs is considered a separate offense. If a Regulated Party fails to retire a sufficient number of WREGIS certificates to meet its RES Obligation by any Compliance Deadline, there is a separate violation for each required WREGIS certificate that has not been retired by the Compliance Deadline.

Part 4 enforcement provisions set out maximum penalty amounts based on the level of culpability of the violator. The statute does not set out minimum penalty amounts. For violations of the proposed RES regulation, these maximum amounts would likely range from $1,000.00 per day per violation based on strict liability to $75,000.00 per violation per day for violations resulting from willful and intentional conduct. There are additional provisions that set greater amounts, but the likelihood of violations of the RES involving these provisions is considered remote.

Part 4 also sets out a number of criteria that ARB is to consider in the determination of an appropriate penalty amount (H&SC § 42403)[3]. These factors include consideration

of the frequency of past violations, the duration of the violation, the nature and persistence of the violation, actions taken to ameliorate the violation, and the financial burden to the violator.

AB 32 also provides that the violation of a regulation adopted under AB 32 is to be deemed to have resulted in the emission of an air contaminant. Generally, a violation associated with an emission release is considered more egregious than a violation not resulting in a release.

Additionally, under H&SC § 41513, any violation of an ARB regulation may be enjoined by a court in a civil action brought in the name of the people of the State of California. Violations of the RES regulation may also be pursued under Business and Professions Code § 17200 et seq[5]. (i.e., for unfair business practices), as well as other applicable State law.

The enforcement process would begin when a possible violation of a requirement of the RES is brought to the attention of ARB. A report of a violation may come to ARB in any number of ways. ARB itself may determine that a violation has occurred. ARB will rely on CEC and CPUC to assist in the implementation of the RES and one of those agencies may ascertain that a violation has occurred. A violation may also be self reported. Self reported violations are generally considered more favorably in the enforcement process.

With respect to the RES, the two most likely violations would be the failure to submit a complete report by the date required and the failure to dedicate an amount of WREGIS certificates sufficient to demonstrate compliance with the percentage amount for the relevant compliance period.

Once ARB has been made aware of a violation, ARB gathers all available information and makes the final determination as to whether a violation has in fact occurred. If ARB determines that a violation has occurred, ARB will write a Notice of Violation identifying the requirement violated and a statement of the basis for determination. The Notice of Violation is then issued to the involved party.

At that point, ARB invites the party involved to participate in an office conference to discuss the violation and to provide the party with the opportunity to present all information the party believes is relevant to the matter. Based on the information provided, ARB will review its findings and, if it still determines that a violation has occurred, ARB will propose a resolution.

A resolution may be comprised of a financial penalty, determined based on the factors discussed above, see also H&SC § 42403, and may also propose certain action measures designed to minimize the potential for further violations. As noted above, any financial penalty would be determined based on a number of factors. Although ARB will adhere to the mandates of AB 32 with respect to processing violations, generally a

violation of a reporting requirement will not be deemed to have the same severity as a violation for failure to meet a compliance interval requirement.

ARB's overall goal is to assure compliance with all regulatory requirements. ARB's enforcement efforts, in any enforcement situation, begin with bringing the party back into compliance. Once compliance has been achieved, ARB's enforcement efforts are focused on deterring future noncompliance. ARB does not have an administrative process associated with enforcement under Part 4. If ARB and the party involved cannot mutually agree on a resolution, then ARB must bring a legal action in order to resolve the matter. However, ARB has a very high rate of success in resolving enforcement matters without need to resort to the courts.

F. Interagency Cooperation

ARB staff is continuing to collaborate with CEC and CPUC on the nature and extent of interagency roles for implementation and enforcement of the proposed RES. The ARB Executive Officer may enter into interagency agreements to formalize the role of the energy agencies in providing monitoring, reporting, verification, and other support for the proposed RES regulation. The ARB Executive Officer may enter into memoranda of understanding or interagency agreements with CEC, CPUC or CAISO to assist in the implementation and enforcement of the processes, procedures, and requirements set forth in the proposed RES regulation.

REFERENCES

[1] California Energy Commission, 2008. Renewables Portfolio Standard Eligibility, Third Edition http://www.energy.ca.gov/2007publications/CEC-300-2007-006/CEC-300-2007-006-ED3-CMF.PDF

[2] California Law. Health and Safety Code Section 38580, http://www.leginfo.ca.gov/cgi-bin/displaycode?section=hsc&group=38001-39000&file=38580

[3] California Law. Health and Safety Code Section 42400-42410, http://www.leginfo.ca.gov/cgi-bin/displaycode?section=hsc&group=42001-43000&file=42400-42410

[4] California Law. Health and Safety Code Section 41500-41514.10, http://www.leginfo.ca.gov/cgi-bin/displaycode?section=hsc&group=41001-42000&file=41500-41514.10

[5] California Law. Business and Professions Code Section 17200-17210, http://www.leginfo.ca.gov/cgi-bin/displaycode?section=bpc&group=17001-18000&file=17200-17210

APPENDIX A

Proposed Regulation Order

This Page Intentionally Left Blank

Appendix A
Proposed Regulation Order

Subchapter 10. Climate Change
Article 6. California Renewable Electricity Standard

§ 97000. Purpose

The purpose of this regulation is to reduce greenhouse gas emissions associated with the generation of electricity.

NOTE: Authority cited: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38590, 38592, 38596, 38597, 39600, 39607, 39607.4, and 41511.

§ 97001. Applicability

(a) The provisions of this Article shall be known as the Renewable Electricity Standard or RES. Nothing in this Article shall be construed to alter or amend the requirements of the Renewables Portfolio Standard Program or the rights, privileges created, the duties or obligation imposed by that program.

(b) The provisions of this Article apply to all Regulated parties, except as provided in sections 97003 and 97004.

NOTE: Authority cited: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38590, 38592, 38596, 38597, 39600, 39607, 39607.4, and 41511.

§ 97002. Definitions and Acronyms

(a) For the purposes of this Article, the following definitions apply.

(1) **"California Department of Water Resources"** means the department within the California Resources Agency, established by section 120 of the Water Code, responsible for California's regulation and management of water use.

(2) **"Community aggregator"** means a community aggregator as defined by Public Utilities Code section 366.1(b).

(3) **"Community choice aggregator"** means a community choice aggregator as defined by Public Utilities Code section 331.1.

(4) "**Compliance Deadline**" means March 31 of the year following the end of each compliance interval.

(5) **"Electric service provider"** means an electric service provider as defined by Public Utilities Code section 218.3.

(6) **"Electrical cooperative"** means an electrical cooperative as defined by Public Utilities Code section 2776.

(7) **"Electrical corporation"** means an electrical corporation as defined by Public Utilities Code section 218.

(8) **"Eligible renewable energy resource"** means a generating facility participating in the WREGIS tracking system that is:

(A) Certified as eligible for California's RPS program pursuant to Public Utilities Code section 399.13;
(B) Meets the criteria of the California RPS program, excluding electricity delivery requirements, as determined by ARB; or
(C) Is a RES Qualifying POU Resource as defined in, and limited by, this Article.

(9) **"Executive Officer"** means the Executive Officer of the California Air Resources Board, or his or her designee.

(10) **"Large hydroelectric generation"** means a hydropower generating facility with a 30 MW or larger generating capacity and which otherwise does not meet the definition of a small hydroelectric facility as described under Public Utilities Code section 399.12; and/or is not recognized as an eligible resource for the RPS program as set forth in Public Utilities Code section 399.11 et seq.

(11) **"Local publicly owned electric utility"** means a local publicly owned utility as defined by Public Utilities Code section 224.3.

(12) **"Megawatt-hour or MWh"** means a unit of energy equivalent to one megawatt of electricity supplied for one hour.

(13) **"Procure or procurement"** as related to renewable energy means an ownership or contractual investment to acquire the physical electrical output of an eligible renewable generating resource, and/or the acquisition of a REC.

(14) **"Publicly Owned Utility or POU"** means a local publicly owned electric utility as defined in this Article.

(15) **"Regulated Party"** means any of the following:
(A) Local publicly owned electric utility;
(B) Electrical corporation;
(C) Electric service provider;
(D) Community choice aggregator;
(E) Electrical cooperative;
(F) Community aggregator;
(G) California Department of Water Resources; and
(H) Western Area Power Administration.

(16) **"Renewable Energy Credit or REC"** means one MWh of electricity generated by an eligible renewable energy resource. A REC does not include an emission reduction credit issued pursuant to Health and Safety Code section 40709. A REC also does not include any allowance issued pursuant to a cap and trade or similar program. A REC does not constitute property or a property right. ARB reserves the right to alter or amend the definition of a REC as it is used for demonstrating compliance with this Article.

(17) **"Renewables Portfolio Standard or RPS"** means the Renewables Portfolio Standard" as set forth in Public Utilities Code section 399.11 et seq.

(18) **"RES Obligation"** means the number of WREGIS certificates required to be retired to demonstrate compliance with the requirements of section 97004.

(19) **"RES Qualifying POU Resource"** means a renewable energy resource as defined in section 97002(a)(8)(C), whose electrical generation was both approved by the POU's Governing Board and reported to the California Energy Commission, as contributing towards the POU's RPS eligible generation on or after January 1, 2003, and prior to September 15, 2009, and:

(A) The POU owned the facility prior to or after January 1, 2003, and prior to September 15, 2009, or

(B) Procured the electricity from the facility by contract executed prior to September 15, 2009; and:

(1) The POU procured electricity and RECs, or RECs without electricity; and

(2) The electricity was procured under the terms of the contract in effect on or before September 15, 2009,

and not during any contract term extended or modified after that date.

(3) Upon expiration of a procurement contract under subsection (B) above, RECs procured from a RES Qualifying POU Resource shall no longer be eligible for compliance with the RES and shall be replaced with RECs from an eligible renewable energy resource under subsection 97002(a)(8)(A) or (B).

(20) **"Responsible Official"** means an officer of the Regulated Party having the authority to sign on behalf of the Regulated Party and bind the Regulated Party for all purposes regarding compliance with this Article.

(21) **"Retail end-use customer"** means a residential, commercial, agricultural, industrial, or other electric customer who receives electricity to be consumed as a final product (not for the purpose of resale).

(22) **"Retire or retired"** means to transfer a WREGIS certificate associated with a REC as defined herein, to a WREGIS "retirement subaccount" and thereby committed the certificate to be used for compliance with the RPS and/or RES.

(23) **"Western Area Power Administration"** refers to the power marketing administration within the U.S. Department of Energy for the 15 state region within the central and western United States.

(24) **"Western Electricity Coordinating Council or WECC"** means the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection serving all or part of the 14 Western States and portions of Mexico and Canada.

(25) **"Western Renewable Energy Generation Information System or WREGIS"** refers to the independent, renewable energy tracking system implemented for the region covered by the Western Electricity Coordinating Council.

(26) **"WREGIS Certificate"** means a WREGIS certificate as defined in the WREGIS operating rules in effect at the time of the adoption of this Article, representing a REC.

(b) For the purposes of this Article, the following acronyms apply.

(1) "ARB" means the California Air Resources Board.
(2) "CAISO" means California Independent System Operator.
(3) "CEC" means California Energy Commission.
(4) "CPUC" means California Public Utilities Commission.
(5) "DWR" means the California Department of Water Resources.
(6) "kWh" means kilowatt-hour.
(7) "MWh" means megawatt-hour.
(8) "POU" means local publicly owned electric utility.
(9) "REC" means renewable energy credit.
(10) "RES" means Renewable Electricity Standard.
(11) "RPS" means Renewables Portfolio Standard.
(12) "WAPA" means the Western Area Power Administration.
(13) "WECC" means Western Electricity Coordinating Council.
(14) "WREGIS" means Western Renewable Energy Generation Information System.

NOTE: Authority cited: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38590, 38592, 38596, 38597, 39600, 39607, 39607.4, and 41511.

§ 97003. Partial Exemption

(a) The provisions of this Article, with the exception of subsection 97006(e), shall not apply to a Regulated Party that had annual sales of electricity to retail end-use customers of 200,000 MWh or less, averaged during calendar years 2007 through 2009.

(b) A Regulated Party that is partially exempted from the requirements of this Article under subsection (a) shall demonstrate continued eligibility for the exemption pursuant to section 97006(e).

(c) A Regulated Party that had been partially exempted from the requirements of this Article under subsection (a), and whose sales to retail end-use customers exceed 200,000 MWh in any calendar year after 2009, shall no longer be partially exempted from the requirements of this Article as of January 1st of the next calendar year, notwithstanding sales to retail end-use customers less than 200,000 MWh in any subsequent year. A Regulated Party no longer partially exempt under this section shall fully comply with the requirements of this Article.

(d) A Regulated Party formed after September 15, 2009, shall not be eligible for a partial exemption under this section.

NOTE: Authority cited: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38590, 38592, 38596, 38597, 39600, 39607, 39607.4, and 41511.

§ 97004. Renewable Electricity Standard Obligations

(a) RES Obligation for Regulated Parties

Except as provided in Section 97003, each Regulated Party (other than DWR and WAPA) shall retire an amount of WREGIS certificates sufficient to demonstrate compliance with the Regulated Party's RES Obligation for each compliance interval. Compliance intervals and the associated REC percentages are specified in Table 1. WREGIS certificates retired for the purpose of demonstrating compliance with the RES Obligation for each compliance interval shall be retired no later than the Compliance Deadline for each compliance interval. The RES obligation shall be calculated as follows:

RES Obligation = Sum of sales to retail end-use customers for the compliance interval × the REC percentage for the compliance interval.

Table 1. Compliance Intervals and REC Percentages

Compliance Intervals	REC Percentage
2012 through 2014	20
2015 through 2017	24
2018 through 2019	28
2020 and annually thereafter	33

(b) RES Obligation for Loss of Partial Exemption

(1) A Regulated Party no longer exempt under section 97003, shall annually retire WREGIS certificates from eligible renewable energy resources, by March 31 after the end of each calendar year pursuant to the following formula:

RES Obligation = Total sales to retail end-use customers in MWh – 200,000 MWh

If the calculated RES Obligation is less than zero, then there is no RES Obligation for that calendar year. No part of the exemption threshold shall be banked or traded as a REC.

(2) When a previously exempt Regulated Party's RES Obligation calculated under subsection 97004(b)(1) equals or exceeds a RES Obligation calculated under subsection 97004(a) for the applicable

compliance interval, the Regulated Party shall comply with subsection 97004(a).

(c) RES Option for Regulated Parties with Large Hydroelectric Generation

(1) A Regulated Party receiving greater than 67 percent of its electricity used for sales to retail end-use customers from hydroelectric generation that does not meet the eligible renewable energy resources definition of this Article, and which was procured by ownership or contract executed prior to September 15, 2009, shall have a RES Obligation equivalent to the amount of sales to retail end-use customers not met by the hydroelectric generation, by the Compliance Deadline for compliance interval, as specified in Table 1.

RES Obligation = Total sales to retail end-use customers in MWh – sales to retail end-use customers from hydroelectric generation in MWh.

(2) A Regulated Party that chooses the RES compliance option under subsection 97004(c)(1), shall notify ARB in writing of its intent to comply with the requirements of this Article pursuant to this subsection by December 31, 2011. The decision to comply with the RES Obligation under subsection 97004(c)(1) cannot be withdrawn or amended once made.

(d) No part of this section 97004 shall apply to or create any obligation on the part of DWR or WAPA.

NOTE: Authority cited: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38590, 38592, 38596, 38597, 39600, 39607, 39607.4, and 41511.

§ 97005. Renewable Electricity Standard Requirements

(a) RECs must be tracked by the WREGIS system to be eligible to satisfy the requirements of section 97004. Consistent with the definition of "eligible renewable energy resource" in section 97002(a)(8), RECs used for compliance with this Article may only be acquired from:

(1) A generating facility certified as eligible for California's RPS program pursuant to Public Utilities Code section 399.13; or

(2) An eligible renewable energy resource that meets all requirements of California's RPS program, excluding electricity delivery requirements, as determined by ARB; or

(3) A RES Qualifying POU Resource, for those POUs that meet the provisions of section 97002(a)(19).

(b) Use of WREGIS certificates

(1) WREGIS certificates must be retired in WREGIS to be eligible for demonstrating RES compliance.

(2) WREGIS certificates retired to meet California's RPS program compliance may also be used to demonstrate compliance with this Article.

(3) Exclusive use

(i) Except as provided in section 97005(b)(2) above, a WREGIS certificate retired to demonstrate compliance with this Article may not also be used to meet the regulatory or voluntary requirements of any other federal, state, or local program ("secondary program").

(ii) In the event that a Regulated Party has retired or attempts to retire a WREGIS certificate to demonstrate compliance with this Article and also to meet a regulatory or voluntary requirement of a secondary program, the WREGIS certificate will be deemed ineligible for any use under this Article at the time such certificate is dedicated to meet such requirement of a secondary program.

(c) RECs procured from a RES Qualifying POU Resource may be used by the initial POU owner or procurer for up to the amount of its RES Obligation equal to 20 percent of its retail sales to end-use customers during calendar year 2010.

(d) *Banking and Trading of RECs.* For purposes of meeting a RES Obligation, RECs may be banked and traded subject to the following limitations:

(1) A REC may be retained or traded for a period of up to three calendar years from the date WREGIS issued the certificate, including the certificate issuance year, or until a REC has been retired into a WREGIS retirement subaccount, whichever occurs first.

(2) A REC must be moved to a WREGIS retirement subaccount within three calendar years from the date WREGIS issued the certificate,

including the certificate issuance year, to be used towards a RES Obligation. A REC placed in a retirement subaccount that is not used to meet a compliance requirement under section 97004, may be banked without limit to meet a future RES Obligation.

(3) RECs generated or procured from a RES Qualifying POU Resource may be banked by the original REC owner. RECs generated or procured from a RES Qualifying POU Resource may not be sold or traded to any other entity.

(4) RECs generated or procured by a Regulated Party operating under the partial exemption in subsection 97003, are not eligible for sale, banking or trading.

Nothing in this subsection (d) shall be construed to limit the use, banking, or trading of RECs not used to meet RES Obligations under this Article.

NOTE: Authority cited: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38590, 38592, 38596, 38597, 39600, 39607, 39607.4, and 41511.

§ 97006. Monitoring, Verification, and Compliance

(a) *WREGIS Verification.* Each Regulated Party, except those exempted by section 97003 and DWR and WAPA, shall register with WREGIS and maintain compliance with all WREGIS requirements.

(b) *Filing of Achievement Plans.* By July 1, 2012, each Regulated Party, except those exempted by section 97003 and DWR and WAPA, shall submit an achievement plan to ARB for the overall 2020 RES target containing the following information:

(1) Regulated Party Information
  (A) Entity name, contact name, mailing address, phone number, and email address;
  (B) Name of Responsible Official for entity; and
  (C) Entity WREGIS account identification number.

(2) Achievement Plan Information
  (A) The applicable compliance subsection under section 97004;
  (B) A plan and procurement strategy, including any known procurement or project development activities by contract and resource type, sufficient to demonstrate how the Regulated Party plans to achieve and maintain the 33 percent RES requirement by 2020.

(c) *Filing of Annual Progress Reports.* Beginning July 1, 2013, and July 1st of each year thereafter, each Regulated Party, except those exempted by section 97003 and DWR and WAPA, shall submit the following information for the prior calendar year to ARB:

(1) Regulated Party Information
  (A) Entity name, contact name, mailing address, phone number, and email address;
  (B) Name of and contact information for Responsible Official for entity; and
  (C) Entity WREGIS account identification number.

(2) RES Annual Progress Information
  (A) Number of WREGIS certificates retired for reporting year by facility identification number; and
  (B) Amount of sales to retail end-use customers for reporting year.

(d) *Filing of Compliance Interval Reports.* By July 1, 2015, July 1, 2018, July 1, 2020, and on July 1st annually thereafter, each Regulated Party, except those exempted under section 97003 and DWR and WAPA, shall submit the following information for the preceding compliance interval to ARB:

(1) Regulated Party Information
  (A) Entity name, contact name, mailing address, phone number, and email address;
  (B) Name of Responsible Official for entity; and
  (C) Entity WREGIS account identification number.

(2) RES Compliance Information
  (A) The applicable compliance subsection under 97004;
  (B) Total sales to retail end-use customers during the compliance interval;
  (C) RES Obligation for the compliance interval;
  (D) Number of WREGIS certificates retired during the compliance interval for the purpose of demonstrating compliance with the RES Obligation for that compliance interval; and
  (E) Number of WREGIS certificates retired between the end of the compliance interval to the Compliance Deadline for the purpose of demonstrating compliance with the RES Obligation for the preceding compliance interval.

(3) Project Status Report
A project development status report on any project development activities, including site control, permitting status, financing status,

interconnection progress, and transmission access during the next compliance interval, consistent with the achievement plan submitted under 97006(b) above.

(4) RES Obligation Deficiency
In the event that a Regulated Party's compliance interval report, filed under subsection (2) above, indicates that the RES Obligation was not met, the Regulated Party shall also submit the following:
(A) Documentation of the RES Obligation deficiency, expressed in MWh; and
(B) A schedule to meet the shortfall within the current year.

(e) A Regulated Party partially exempted pursuant to section 97003 shall report to ARB by July 1, 2013, and July 1st of each year thereafter, its total sales to retail end-use customers for the prior calendar year, in MWh.

(f) *DWR and WAPA Reporting.* Beginning July 1, 2013, and July 1st of each year thereafter, DWR and WAPA shall submit the following information for the prior calendar year to ARB:

(1) Information Requirements
(A) Contact name, mailing address, phone number, and email address; and
(B) Name of and contact information for Responsible Official for entity;

(2) Electricity Procured or Generated
(A) For each contract or transaction engaged in for the purchase of electricity, specify the amount of electricity procured or generated, the generator fuel type, and the name and location of the entity or power pool from which the electricity was purchased; and
(B) For each owned source used to generate electricity, specify the total amount of electricity generated, the name and location of the generator, and the generator fuel type.

(3) Electricity Used or Sold
(A) Identify the total amount of electricity used to convey, pump, and store water, or to serve individual water delivery contracts;
(B) For each contract or transaction engaged in for the sale of electricity to retail end-use customers, specify the total amount of electricity sold, the name and location of the generator or source of sold power, the generator or contract source fuel type, and the name and location of the entity to whom the electricity was sold; and

(C) For each contract or transaction engaged in for the sale of electricity not reported pursuant to subsection (B) above, specify the total amount of electricity sold, the name and location of the generator or source of sold power, the generator or contract source fuel type, and the name and location of the entity to whom the electricity was sold.

(g) *Recordkeeping Requirements.* All Regulated parties must retain copies of all information and records required by this Article or necessary for verifying the accuracy of any information required by this Article or included in the Regulated Party's applications, or reports required by this Article for no less than seven years. A Regulated Party shall allow the inspection and duplication of such information and records or provide such information and records within 30 days of a written request received from the Executive Officer or designee.

NOTE: Authority cited: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38590, 38592, 38596, 38597, 39600, 39607, 39607.4, and 41511.

§ 97007. Certification of Eligible Renewable Energy Resources

(a) An Eligible renewable energy resource may be certified by any of the following:

(1) The CEC as meeting the eligibility requirements for the RPS program;

(2) The CEC under an interagency agreement with ARB, as meeting eligibility requirements for the RPS program, except as to any delivery requirement;

(3) The CEC under an interagency agreement with ARB for a RES Qualifying POU Resource using the criteria of section 97002(a)(19); or

(4) The Executive Officer, his/her designee, or a third party contractor under contract with ARB, using the same criteria that would be used by the CEC under (2) or (3) above.

(b) Applicants seeking certification of a renewable energy resource for eligibility under the existing RPS program shall file the application in accordance with that program's requirements.

(c) Applicants seeking certification of a generating facility for eligibility under this Article shall file the application with the Executive Officer using a form

or forms approved by the Executive Officer. The Executive Officer may enter into an interagency agreement with the CEC or a third party contractor to review and make recommendations as to certification and verification of the generating facility for eligibility.

NOTE: Authority cited: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38590, 38592, 38596, 38597, 39600, 39607, 39607.4, and 41511.

§ 97008. Interagency Cooperation

The Executive Officer may enter into memoranda of understanding or interagency agreements with appropriate parties, including the CEC and CPUC, to assist in the implementation of the processes, procedures, and requirements set out in this Article.

NOTE: Authority cited: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38590, 38592, 38596, 38597, 39600, 39607, 39607.4, and 41511.

§ 97009. Enforcement

(a) *Penalties.* Penalties may be assessed for any violation of this Article pursuant to Health and Safety Code section 38580.

(b) *Violations.* A violation of the requirements of this Article shall be deemed to result in an emission of an air contaminant.

(1) Each day or portion thereof that a Regulated Party violates or remains in violation of a requirement of this Article is a separate violation. Each day or portion thereof that any report required by this Article remains unsubmitted, is submitted late, or contains incomplete or inaccurate information, shall constitute a separate violation of this Article.

(2) If a Regulated Party fails to retire a sufficient number of WREGIS certificates to meet its RES Obligation by the date specified in section 97004, there is a separate violation of this Article for each required WREGIS certificate that has not been retired by the Compliance Deadline. There is also a separate violation for each day or portion thereof after the Compliance Deadline that each required WREGIS certificate has not been retired.

NOTE: Authority cited: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety

Code. Reference: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38590, 38592, 38596, 38597, 39600, 39607, 39607.4, and 41511.

§ 97010. Treatment of Confidential Information

Information submitted pursuant to this Article may be claimed as confidential. A Regulated Party shall designate such information as confidential at the time it is submitted and shall describe the basis for such designation. Information claimed as confidential shall be handled in accordance with the procedures specified in Cal. Code Regs., title 17, sections 91000 – 91022.

NOTE: Authority cited: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38590, 38592, 38596, 38597, 39600, 39607, 39607.4, and 41511.

§ 97011. Regulation Review

(a) The Executive Officer, in coordination with the CEC, CPUC and CAISO, shall conduct at least three reviews of the RES program to assess changes that may be needed to improve implementation progress. Reviews shall be completed and presented to the Board by December 31, 2013, December 31, 2016, and December 31, 2018.

(b) RES program reviews may consider information made available through the proceedings of the CEC, CPUC and CAISO relevant to the integration of renewable energy into the electricity system. The scope of each review shall include consideration of the following:

(1) Regulated Party compliance progress under section 97004;

(2) Compliance interval adjustments needed to reduce costs and increase benefits for California's economy, improve and modernize California's energy infrastructure, maximize potential greenhouse gas and criteria pollutant emission reductions, and maintain electric system reliability;

(3) Advances in renewable energy generation technologies, and complementary storage technologies, and the feasibility and cost effectiveness of such advances that may contribute to the effectiveness of program implementation;

(4) Availability and supplies of eligible renewable resources and renewable energy credits within the WECC;

(5) Impacts of integrating variable renewable energy resources on the State's energy supplies and reliability of the electricity system in

consultation with information developed by the CEC, CPUC and CAISO;

(6) Impacts on electric rates, consumers, and economic growth;

(7) Analysis of public health impacts, including the operational impacts of generating facilities, demand response measures, and storage facility development needed to implement this Article;

(8) Assessment of air quality impacts on California associated with implementation of this Article, including effects on attainment of State or federal air quality standards;

(9) Impact of renewable energy development barriers or delays encountered by Regulated parties, such as transmission permitting and development issues; and

(10) Opportunities to harmonize the RES with any federal, regional, or other state renewable energy programs or REC markets.

(c) The Executive Officer shall conduct the reviews specified above in a public process and shall conduct at least one public workshop for each review prior to presenting its findings to the Board. In presenting the results of each program review to the Board, the Executive Officer shall propose any amendments or such other action as the Executive Officer determines is warranted.

NOTE: Authority cited: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38590, 38592, 38596, 38597, 39600, 39607, 39607.4, and 41511.

§ 97012. Severability

Each part of this Article is deemed severable and in the event that any part of this Article is held to be invalid, the remainder of this Article shall continue in full force and effect.

NOTE: Authority cited: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38596, 38597, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38501, 38510, 38551, 38560, 38562, 38563, 38564, 38570, 38571, 38580, 38590, 38592, 38596, 38597, 39600, 39607, 39607.4, and 41511.

This Page Intentionally Left Blank

TITLE 17. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER THE ADOPTION OF PROPOSED REGULATION FOR ENERGY EFFICIENCY AND CO-BENEFITS ASSESSMENT OF LARGE INDUSTRIAL FACILITIES

The Air Resources Board (ARB or Board) will conduct a public hearing at the time and place noted below to consider adopting a regulation affecting large industrial stationary facilities located in California. The primary purpose of the proposed regulation is to gather information on the energy efficiency improvement opportunities that are available to California's largest industrial stationary sources of greenhouse gases (GHG), and to quantify the associated potential emission reductions for GHG, criteria pollutants, and toxic air contaminants.

DATE: July 22, 2010

TIME: 9:00 a.m.

PLACE: California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium, Second Floor
1001 I Street
Sacramento, California 95814

This item may be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., July 22, 2010, and may continue at 8:30 a.m., on July 23, 2010. This item may not be considered until July 23, 2010. Please consult the agenda for the hearing, which will be available at least 10 days before July 22, 2010, to determine the day on which this item will be considered.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Sections Affected: Proposed adoption of California Code of Regulations (CCR), title 17, subchapter 10, article 2.1. Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities, sections 95150, 95151, 95152, 95153, 95154, 95155, 95156, 95157, 95158, 94159, 95160, 95161, and 95162.

Background: In 2006, the Governor signed California's Global Warming Solutions Act (AB 32), which set the State's GHG reduction goals into law. AB 32 directed the ARB to begin developing discrete early actions to be made enforceable by 2010 and to prepare a Scoping Plan that will identify how best to reach the 2020 greenhouse gas limit. The Board approved the Scoping Plan in December 2008. In the Scoping Plan, the Board outlined a comprehensive set of actions to reduce GHG emissions. This proposed regulation is one of the many measures identified in the Scoping Plan. The goals for the proposed regulation are to:

1) for high GHG emitting stationary industrial facilities in California, identify the facility's energy consumption and the associated GHG, criteria pollutant, and toxic air contaminant emissions;
2) determine potential energy efficiency improvement opportunities for reducing GHG, criteria pollutant, and toxic air contaminant emissions; and
3) identify potential future actions for obtaining further reductions.

Industrial facilities in California are a large source of GHG emissions. In 2008, these facilities emitted approximately 160 million metric tonnes of carbon dioxide equivalent ($MMTCO_2e$) emissions annually or about one-third of the total GHG emissions from all sources in California. Information gathered from the implementation of the proposed regulation will be a valuable resource in determining what GHG emission reduction opportunities are available as well as what criteria pollutant and toxic air contaminant co-benefits might be realized. ARB staff will use these data to inform ARB's GHG, criteria pollutant, and toxic air contaminant emission reduction programs, and the next update to the Scoping Plan. Additionally, the information will help California's largest stationary sources of GHG emissions consider potential co-benefits when deciding on actions to comply with other GHG programs, such as a cap-and-trade program.

DESCRIPTION OF THE PROPOSED REGULATORY ACTION

ARB staff is proposing a regulation (article 2.1, subchapter 10, title 17, sections 95150 to 95162, CCR) that will subject the largest stationary sources of GHG emissions in California to provide information on the energy efficiency improvement opportunities that are available, and quantify the associated emission reductions for GHG, criteria pollutants, and toxic air contaminants.

Applicability

The proposed regulation would apply to stationary sources that emit GHG emissions of greater than 0.5 $MMTCO_2e$ annually and transportation fuel refineries and cement plants that emit GHG emissions of greater than 0.25 $MMTCO_2e$ annually. Besides refineries and cement plants, these facilities include oil and gas extraction and transmission facilities, electricity generation facilities, mineral plants, and hydrogen production facilities. Based on the emissions threshold and the GHG emissions data collected for the 2008 calendar year pursuant to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, sections 95100 through 95133, title 17, CCR (Mandatory GHG Reporting Regulation), approximately 60 facilities in five industrial sectors will be affected. The industrial sectors and the number of facilities include:

- petroleum refineries (18 facilities)
- oil and gas extraction and transmission facilities (6 facilities)
- electricity generating facilities (18 facilities)
- cement plants and mineral plants (11 facilities)
- hydrogen plants (3 facilities)

The combined total GHG emissions at these 60 facilities was about 70 $MMTCO_2e$ in 2008 or about 45 percent of the total emissions from the industrial sector. These facilities are located throughout California with the largest numbers found in the Southern San Joaquin Valley, and in and around Los Angeles and San Francisco.

Analysis of Facility Energy Consumption and Emissions

Facility operators would be required to provide a process flow diagram, the name and description of the processes and equipment used, and the facility-wide fuel and electricity consumption for the 2009 calendar year. The proposed regulation does not require facilities to create a new emissions inventory. Instead, facilities would provide their 2009 calendar year emissions of GHG, criteria pollutants, and toxic air contaminants that were reported for the Mandatory GHG Reporting Regulation (for GHG) and local air district reporting programs (for criteria pollutants and toxic air contaminants). The GHG emissions data reported will be validated by a third party verification process that is required by the Mandatory GHG Reporting Regulation. The criteria pollutant and toxic air contaminant emission data will be verified by ARB and district staff as part of their existing data validation and review programs.

Analysis of Potential Energy Efficiency Improvements

Facility operators would be required to conduct a comprehensive assessment of potential energy efficiency improvement projects that are possible at the facility and the associated impacts that would occur if the projects were implemented. The assessment would include a description of each project, the types of processes and equipment involved, preliminary estimates for costs, timing, status (if the project is being implemented), project life, energy and cost savings, potential emission reductions (GHG, criteria pollutant and toxic air contaminant), district permitting impacts, and other project related impacts.

Submittal of a Comprehensive Report

Facility operators would be required to submit a report, called the Assessment Report, containing the facility's energy consumption and emissions analysis and the energy efficiency improvement analysis. The Assessment Reports would be submitted to ARB by the end of 2011, and would then undergo an internal ARB review process to determine completeness and validity. If a report is deemed to be incomplete, then a new assessment, conducted by an approved third party assessor, may be required. Completed assessment reports submitted to the ARB would be made publicly available on an ARB's Climate Change website in April 2012. Staff will also develop a draft report, to be released in mid 2012, with preliminary findings and recommendations. This draft report will be used as a starting point for discussion with all stakeholders on opportunities for further emission reductions.

Exemptions

The requirements of the proposed regulation would not apply to combined-cycle electricity generating facilities built after 1995. These facilities are considered to have the most efficient power generation process and equipment available, as determined by the California Energy Commission.

The proposed regulation also includes an exemption for petroleum refineries that do not produce transportation fuels, such as asphalt plants, because their processes are less energy intensive, emissions are typically less than transportation fuel refineries, and there are a limited number of facilities.

The proposed regulation would also exempt mobile source combustion sources and portable equipment. The Scoping Plan measure for this regulation intended it to focus on stationary sources only, and mobile and portable equipment are not required reporting sources for the Mandatory GHG Reporting Regulation.

COMPARABLE FEDERAL REGULATIONS

There are no comparable federal regulations at this time.

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

ARB staff has prepared a Staff Report: Initial Statement of Reasons (ISOR) for the proposed regulatory action, which includes a summary of the economic and environmental impacts of the proposed regulatory amendments and which also describes the basis of the proposed action in more detail. The Staff Report is entitled, "Staff Report: Initial Statement of Reasons for the Proposed Rulemaking – Proposed Regulation for Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities."

Copies of the ISOR with the full text of the proposed regulatory language may be accessed on the ARB's website listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California 95814, (916) 322-2990 at least 45 days prior to the scheduled hearing on July 22, 2010.

Upon its completion, the Final Statement of Reasons (FSOR) will be available and copies may be requested from the agency contact persons in this notice, or may be accessed on the ARB's website listed below.

Inquiries concerning the substance of the proposed regulation may be directed to the designated agency contact person, Lisa Williams, Air Pollution Specialist, at (916) 327-1498.

Further, the agency representative and designated back-up contact persons, to whom nonsubstantive inquiries concerning the proposed administrative action may be directed are Lori Andreoni, Manager, Board Administration & Regulatory Coordination Unit, (916) 322-4011, and Trini Balcazar, Regulations Coordinator, (916) 445-9564. The Board has compiled a record for this rulemaking action, which includes all the information upon which the proposal is based. This material is available for inspection upon request to the contact persons.

This notice, the Staff Report, and all subsequent regulatory documents, including the FSOR, when completed, are also available on the ARB website for this rulemaking at http://www.arb.ca.gov/regact/2010/energyeff10/energyeff10.htm.

COSTS TO PUBLIC AGENCIES AND TO BUSINESSES AND PERSONS AFFECTED

Costs to Businesses and Private Individuals

The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies and private persons and businesses in reasonable compliance with the proposed amendments are presented below.

The affected businesses are the largest industrial stationary sources of GHG emissions in California. The majority of the businesses affected by the proposed regulation are large multi-national corporations. While we do not expect these businesses to be adversely affected by the costs of the proposed regulation, there will be costs associated with conducting the assessment, compiling the data, and submitting the report to the ARB. The specific cost for an individual facility subject to the regulation will generally depend on the complexity of the facility and ranges from $78,000 to $425,000. Staff estimates the total costs for compliance with the proposed regulation to be approximately $14 million over a period of about 16 to 18 months.

Therefore, the Board's initial determination is that there will be no significant, statewide adverse economic impact directly affecting business, including the ability of California businesses to compete with businesses in other states."

The profitability of California businesses affected by the proposed one-time cost of the proposed regulation should be minimal. Overall, affected businesses will be able to absorb the costs of the proposed regulation with no significant adverse impacts on their profitability. Because the proposed regulation would not alter significantly the profitability of most businesses, we do not expect a noticeable change in employment, business creation, elimination, or expansion, and business competitiveness in California for these industries.

The ARB staff has considered alternatives to the proposed regulation and evaluated the economic impact on businesses. None of the alternatives considered would achieve the objectives of the proposed regulation at a lower cost. The alternatives that staff considered are described in more detail in the Staff Report.

In accordance with Government Code section 11346.3, the Executive Officer has determined that the proposed regulatory action would not affect the creation or elimination of jobs within the State of California, the creation of new businesses or elimination of existing businesses within the State of California, or the expansion of businesses currently doing business within the State of California. A detailed assessment of the economic impacts of the proposed regulatory action can be found in the Staff Report.

The Executive Officer has also determined, pursuant to title 1, CCR, section 4, that the proposed regulatory action would not affect small businesses because, together with its affiliates, they either exceed 100 employees or have average annual gross receipts greater than $12 million over the previous three tax years.

In accordance with Government Code section 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that the proposed regulatory action would not create costs or savings in federal funding to the State, or costs or mandate to any local agency or school district whether or not reimbursable by the State pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government code or other nondiscretionary cost or savings imposed upon local agencies.

In accordance with Government Code sections 11346.3(c) and 11346.5(a)(11), the Executive Officer has found that the reporting requirements of the proposed regulation which apply to businesses are necessary for the health, safety, and welfare of the people of the State of California.

Before taking final action on the proposed regulatory action, the Board must determine that no reasonable alternative considered by the Board, or that has otherwise been identified and brought to the attention of the Board would be more effective in carrying out the purpose for which the action is proposed, or would be as effective and less burdensome to affected private persons than the proposed action.

Costs to Local and State Government Agencies

Pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that the proposed regulatory action would create no costs to federal agencies.

The State, and almost all local, agencies do not own any electricity generating facilities, refineries, oil and gas extraction fields, cement plants, hydrogen plants, or mineral plants that are subject to this regulation.

No fiscal impact is expected on any local entity or program. The Los Angeles Department of Water and Power (LADWP) owns three electricity generating facilities that are subject to the proposed regulation. In addition, the Puente Hill landfill electricity generating facility is operated by the Los Angeles County Sanitation District. These facilities operate as not-for-profit corporations; thus their compliance costs, about

$78,000 per facility or about $300 thousand dollars combined, are included in the total costs of the proposed regulation. Because these facilities recover any costs from their client via service fees, local tax payers would not be impacted through fiscal budgets. ARB will incur minimum costs to administer the proposed regulation. These costs would be met with existing resources. No other State agencies will be affected. A detailed assessment of the economic impacts of the proposed regulatory action can be found in the Staff Report.

SUBMITTAL OF COMMENTS

Interested members of the public may also present comments orally or in writing at the meeting, and comments may be submitted by postal mail or by electronic submittal before the meeting. The public comment period for this regulatory action will begin on June 7, 2010. To be considered by the Board, written comments, not physically submitted at the meeting must be submitted on or after June 7, 2010 and received **no later than 12:00 noon, Pacific Standard Time, July 21, 2010,** and must be addressed to the following:

Postal mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

Please note that under the California Public Records Act (Gov. Code, § 6250 et seq.), your written and oral comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request. Additionally, this information may become available via Google, Yahoo, and any other search engines.

The Board requests, but does not require, that 20 copies of any written statement be submitted and that all written statements be filed at least 10 days prior to the hearing so that ARB staff and Board members have time to fully consider each comment. The Board encourages members of the public to bring to the attention of staff in advance of the hearing any suggestions for modification of the proposed regulatory action.

STATUTORY AUTHORITY AND REFERENCES

This regulatory action is proposed under the authority granted to ARB in Health and Safety Code sections 38510, 38530, 38560, 38562, 39600, 39601, 39659, and 41511. This action is proposed to implement, interpret, and make specific Health and Safety Code sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, 39003, 39500, 39600, 39601, 39659, and 41511.

HEARING PROCEDURES

The public hearing will be conducted in accordance with the California Administrative Procedure Act, title 2, division 3, part 1, chapter 3.5 (commencing with §11340) of the Government Code.

Following the public hearing, the Board may adopt the regulatory language as originally proposed, or with non-substantial or grammatical modifications. The Board may also adopt the proposed regulatory language with other modifications if the text as modified is sufficiently related to the originally proposed text that the public was adequately placed on notice that the regulatory language as modified could result from the proposed regulatory action. In the event that such modifications are made, the full regulatory text, with the modifications clearly indicated, will be made available to the public, for written comment, at least 15 days before it is adopted.

The public may request a copy of the modified regulatory text from ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814, (916) 322-2990.

To request a special accommodation or language needs for any of the following:

- An interpreter to be available at the hearing.
- Have documents available in an alternate format (i.e. Braille, Large print) or another language.
- A disability-related reasonable accommodation.

Please contact the Clerk of the Board at (916) 322-5594 or by facsimile at (916) 322-3928 as soon as possible, but no later than 10 business days before the scheduled Board hearing. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Para solicitar alguna comodidad especial o necesidad de otro idioma para alguna de las siguientes:

- Un intérprete que esté disponible en la audiencia
- Tener documentos disponibles en un formato alterno (por decir, sistema Braille, o en impresión grande) u otro idioma.
- Una acomodación razonable relacionados con una incapacidad.

Por favor llame a la oficina del Secretario del Consejo de Recursos Atmosféricos al (916) 322-5594 o envíe un fax al (916) 322-3928 no menos de diez (10) días laborales antes del día programado para la audiencia. Para el Servicio Telefónico de California para Personas con Problemas Auditivos, ó de teléfonos TDD pueden marcar al 711.

CALIFORNIA AIR RESOURCES BOARD

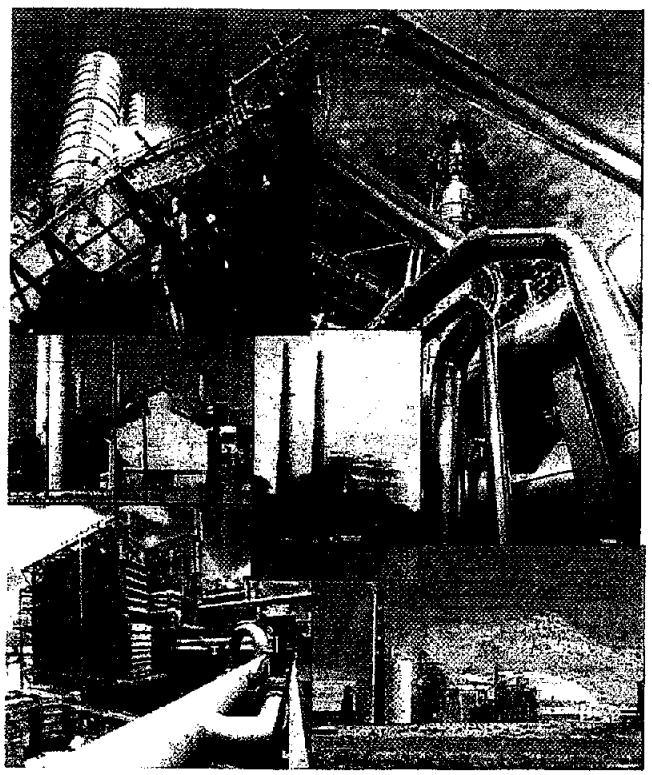
James N. Goldstene
Executive Officer

Date: May 25, 2010

The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs see our website at www.arb.ca.gov.

California Environmental Protection Agency
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR PROPOSED RULEMAKING



REGULATION FOR ENERGY EFFICIENCY AND CO-BENEFITS ASSESSMENT OF LARGE INDUSTRIAL FACILITIES

Stationary Source Division
Emissions Assessment Branch

June 2010

State of California
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR PROPOSED RULEMAKING

Public Hearing to Consider

ADOPTION OF THE PROPOSED ENERGY EFFICIENCY AND CO-BENEFITS ASSESSMENT OF LARGE INDUSTRIAL FACILITIES

To be considered by the Air Resources Board on July 22-23, 2010, at:

California Environmental Protection Agency
Headquarters Building
1001 "I" Street
Byron Sher Auditorium
Sacramento, California

Stationary Source Division:
Richard Corey, Chief
Daniel E. Donohoue, Chief,
Emissions Assessment Branch
Cherie Rainforth, Manager
Control Strategies Section
Peggy Taricco, Manager
Technical Analysis Section

This report has been prepared by the staff of the Air Resources Board. Publication does not signify that the contents reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

State of California
AIR RESOURCES BOARD

PROPOSED REGULATION FOR ENERGY EFFICIENCY AND CO-BENEFITS ASSESSMENT OF LARGE INDUSTRIAL FACILITIES

Contributing ARB Staff

Lisa Williams (Lead)
Kirk Rosenkranz
Michele Houghton
Layla Lenderman
Zhenlei Wang
John Lee
Douglas Grandt
Greg Harris
Ziv Lang
Hafizur Chowdhury

Legal Counsel

Aron Livingston, Office of Legal Affairs

Supporting Divisions

Planning and Technical Support Division
Research Division

Acknowledgements

This report was prepared with the assistance and support from the other divisions and offices of the Air Resources Board. In addition, we would like to acknowledge the assistance and cooperation that we have received from many individuals and organizations.

TABLE OF CONTENTS

Contents **Page**

Executive Summary ES-1

I. Introduction 1
A. Overview 1
B. Primary Enabling Legislation 1
C. Statutory Requirements 2
D. Existing Regulations and Programs 5
E. Development of the Proposed Regulation 8

II. Sectors and Facilities 10
A. Sectors and Facilities Subject to the Proposed Regulation 13
B. Estimated 2008 Facility Emissions 21

III. Proposed Regulation 26
A. Summary of the Proposed Regulation 26
B. Discussion of the Proposed Regulation 27

IV. Environmental Impacts of the Proposed Regulation 34
A. Air Quality and Environmental Impacts 34
B. Public Process and Environmental Justice 34

V. Economic Impacts of the Proposed Regulation 36
A. Summary of Costs and Economic Impacts 36
B. Legal Requirements 37
C. Analysis of Estimated Costs for Compliance 37
D. Economic Impacts of the Proposed Regulation 40
E. Alternatives to the Proposed Regulation 45

References 48-49

Appendices:

Appendix A: Proposed Regulation for Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities A-1

Appendix B: Methodology for Presenting Toxic Emissions from Facilities Subject to the Proposed Regulation B-1

TABLE OF CONTENTS (CONT.)

List of Tables **Page**

Table 1: Timeline for Proposed Energy Efficiency Assessment Regulation Implementation ES-6
Table 2: Estimated Facility Costs and Total Costs for Compliance with the Proposed Regulation ES-7
Table 3: Facilities in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation and Their 2008 GHG Emissions 10-11
Table 4: 2008 GHG Emissions by Industrial Sector for the Facilities Expected to be Affected by the Proposed Energy Efficiency Assessment Regulation 21
Table 5: 2008 Criteria Pollutant Emissions by Industrial Sector for the Facilities Expected to be Subject to Proposed Energy Efficiency Assessment Regulation 23
Table 6: Toxic Air Contaminants by Industrial Source Category 24-25
Table 7: Estimated Facility Costs and Total Costs for Compliance with the Proposed Regulation 36
Table 8: Estimated Cost Ranges and Average Cost for Compliance with the Proposed Regulation 38
Table 9: Estimated Costs for Compliance with the Proposed Regulation 39
Table 10: Facilities in California Expected to be Subject tot the Proposed Energy Efficiency Assessment Regulation 41-42
Table 11: Affected Businesses with Change in ROE 43

List of Figures **Page**

Figure 1: Facility Locations in California (2008) Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation ES-3
Figure 2: Distribution of 2008 GHG Emissions by Industrial Sector for the Facilities Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation ES-4
Figure 3: Location of Facilities in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation 12
Figure 4: Location of Petroleum Refineries in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation 14
Figure 5: Location of Oil and Gas Facilities in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation 15
Figure 6: Location of Electricity Generating Facilities in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation 17
Figure 7: Location of Cement and Mineral Facilities in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation 18
Figure 8: Location of Hydrogen Facilities in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation 20

TABLE OF CONTENTS (CONT.)

List of Figures (Cont.) **Page**

Figure 9: Distribution of 2008 GHG Emissions by Industrial Sector for the Facilities Expected to be Subject to the Proposed Energy Assessment Regulation ...22

- This page is intentionally blank -

EXECUTIVE SUMMARY

This summary presents an overview of the Air Resources Board (ARB or Board) staff's *Proposed Regulation for Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities* (Energy Efficiency Assessment Regulation or proposed regulation). The proposed regulation is designed to gather information on the energy efficiency improvement opportunities that are available for California's largest industrial stationary sources of greenhouse gas emissions (GHG), and to quantify the associated emission reductions for greenhouse gases, criteria pollutants, and toxic air contaminants.

In 2006, the Governor signed the California Global Warming Solutions Act (Act or AB 32). Among other provisions, the Act set the State's greenhouse gas emission (GHG) reduction goals into law. The Act directed ARB to prepare a Scoping Plan that identifies how best to reach the 2020 GHG limit. The Board approved the Scoping Plan in December 2008. In the Scoping Plan, the Board outlined a comprehensive set of actions to reduce GHG emissions. The proposed regulation is one of the many measures identified in the Scoping Plan. The goals of the proposed regulation are to:

1) for high GHG emitting industrial stationary facilities in California, identify the energy consumption and the associated GHG, criteria pollutant, and toxic air contaminant emissions;
2) determine potential opportunities for improving energy efficiency and reducing GHG, criteria pollutant, and toxic air contaminant emissions from industrial facilities such as refineries, electricity generating facilities, cement plants, hydrogen plants, and other large industrial facilities; and
3) identify potential future actions for obtaining further reductions in GHG, criteria pollutant, and toxic air contaminant emissions.

Industrial facilities in California are a large source of GHG emissions. In 2008, these facilities emitted approximately 160 million metric tonnes of carbon dioxide equivalent ($MMTCO_2e$) emissions annually or about one-third of the total GHG emissions from all sources in California (ARB, 2010a). Information gathered from the implementation of the proposed regulation will be a valuable resource in determining what GHG emission reduction opportunities are available as well as what criteria pollutant and toxic air contaminant co-benefits might be realized. ARB staff will use these data to inform ARB's GHG, criteria pollutant, and toxic air contaminant emission reduction programs, and the next update to the Scoping Plan. Additionally, the information will help California's largest stationary sources of GHG emissions consider potential co-benefits when deciding on actions to comply with other GHG programs, such as a cap-and-trade program.

Presented below is an overview that briefly discusses the information presented in this Staff Report.

1. What is ARB staff proposing?

ARB staff is proposing a regulation to require selected industrial facilities to provide ARB with information on the key processes and activities, including data on emissions, energy usage, and potential energy efficiency improvement projects. These industrial sectors include petroleum refineries that produce transportation fuels, oil and gas extraction and transmission, electricity producers, cement and mineral production, and hydrogen production.

2. What are the objectives of the proposed regulation?

The objectives of the proposed regulation are to collect information in a one-time assessment to identify the full range of energy efficiency improvement projects and GHG emission reduction opportunities potentially available at California's largest industrial facilities and to identify what criteria pollutants and toxic air contaminants (TAC or toxics) co-benefits could be achieved. The data gathered are meant to provide preliminary estimates on costs, emission reductions, and other impacts that would occur if the identified projects were implemented. Once the information is collected, it will then be used to inform industry, regulatory agencies, and the public on the most effective actions for reducing GHG emissions, criteria pollutant emissions, and toxic air contaminants from these large industrial facilities.

3. What industrial sectors and facilities would be affected?

The proposed regulation will apply to California's largest industrial facilities; those emitting GHG emissions of at least 0.5 $MMTCO_2e$ annually and any cement plants or transportation fuel refineries that emit GHG emissions of at least 0.25 $MMTCO_2e$ annually. Based on this threshold and the 2008 data reported to the ARB pursuant to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions[1] (Mandatory GHG Reporting Regulation), approximately 60 facilities in five industrial sectors will be affected.[2] The sectors include:

- petroleum refineries (18 facilities)
- oil and gas extraction and transmission facilities (6 facilities)
- electricity generating facilities (18 facilities)
- cement plants and mineral plants (11 facilities)
- hydrogen plants (3 facilities)

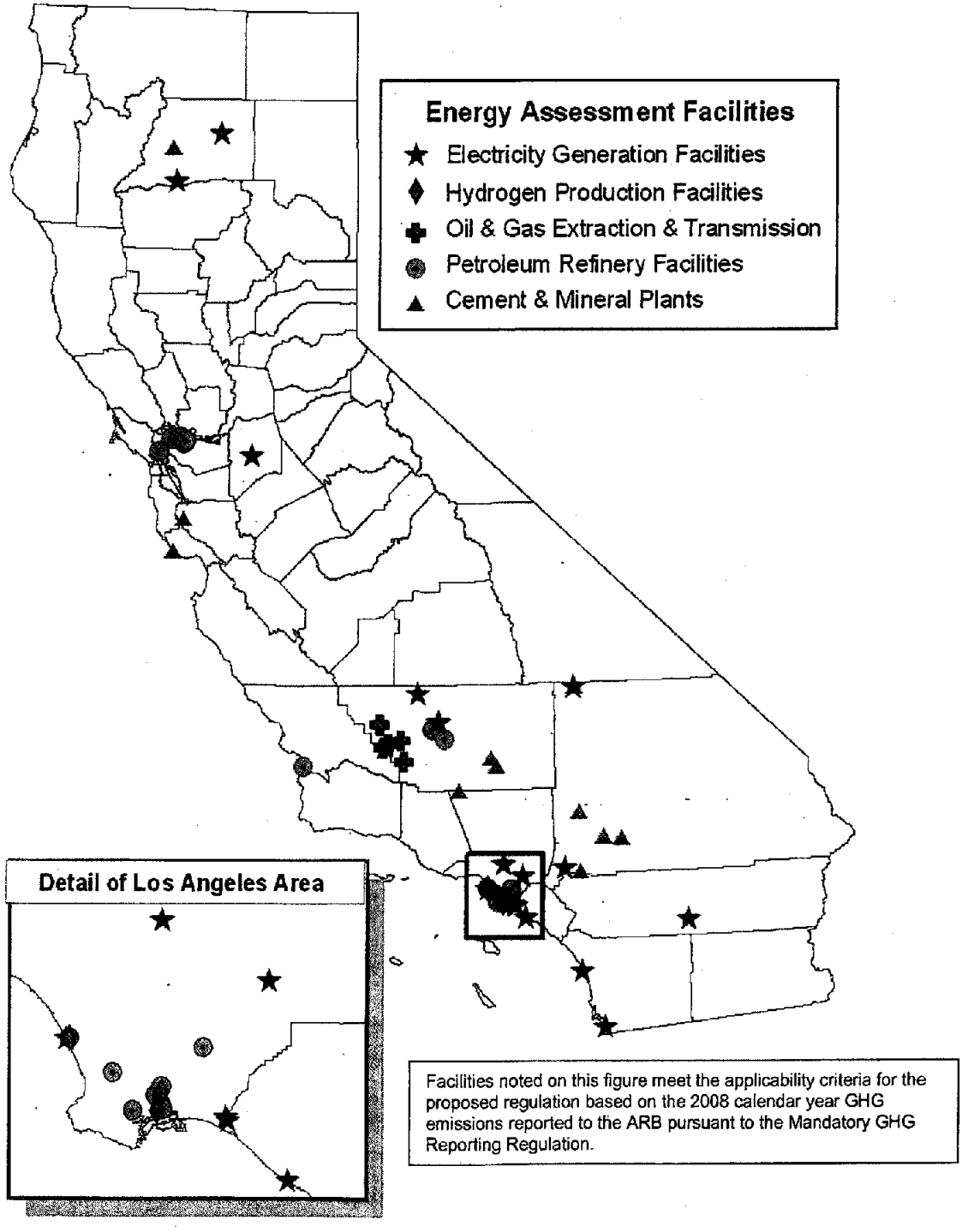
As shown in Figure 1, these facilities are located throughout California with the largest numbers found in the Southern San Joaquin Valley, and in and around Los Angeles and San Francisco. Combined-cycle electricity generating facilities built after 1995 would be

[1] Sections 95100 through 95133, title 17, California Code of Regulations

[2] The actual number of facilities that would be subject to the proposed regulation may be different, since the applicability will be based on the 2009 calendar year data collected under the Mandatory GHG Reporting Regulation, which has not yet been released.

exempt from the proposed regulation because staff finds they are the most energy-efficient facilities within that sector, and implementing the proposed regulation would not have the benefits as great as other facility types.

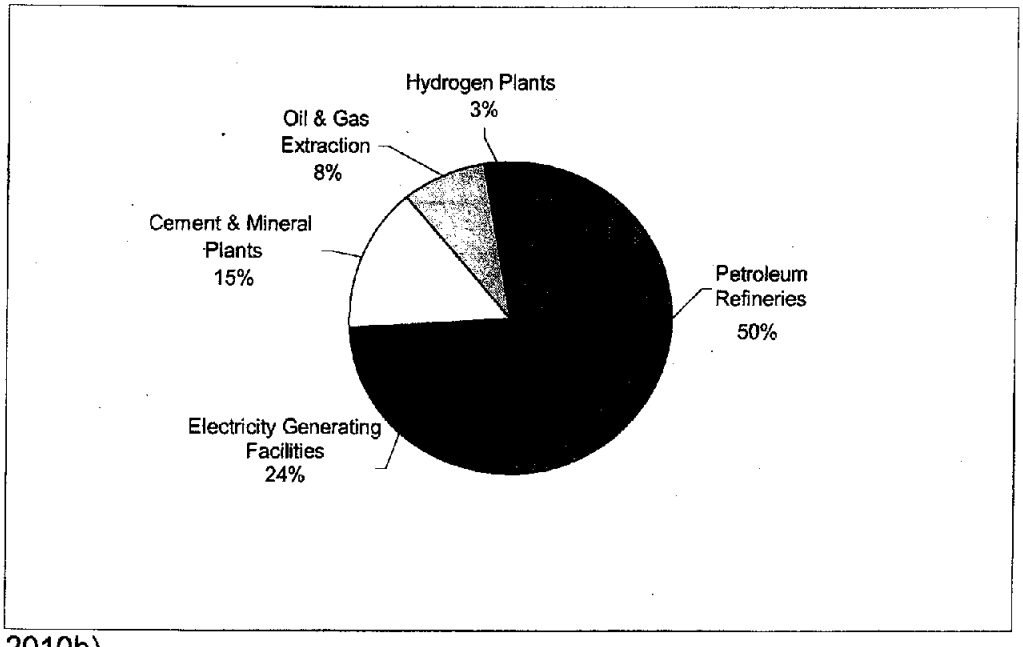
Figure 1: Facility Locations in California (2008) Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation



4. What are the greenhouse gas emissions from the identified facilities?

The combined total GHG emissions at the approximately 60 facilities statewide that are expected to be subject to the proposed regulation was about 70 $MMTCO_2e$ in 2008 or about 45 percent of the total emissions from the industrial sector. This estimate is based on reports submitted by the facilities to comply with the Mandatory GHG Reporting Regulation. Figure 2 below shows the distribution of the emissions from the five sectors.

Figure 2: Distribution of 2008 GHG Emissions by Industrial Sector for the Facilities Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation



(ARB, 2010b)

5. What are the key elements of the proposed regulation?

The proposed regulation has three key elements:

- an analysis of the facility energy consumption and emissions;
- an analysis of the potential for energy efficiency improvements that will result in GHG emission reductions, with additional quantification of associated reductions in criteria pollutants and TACs; and
- a comprehensive report, that would be submitted to ARB containing the information gathered from the two elements above.

As part of the first element, facility operators would be required to provide a process flow diagram, the name and description of the processes and equipment used, and the facility-wide fuel and electricity consumption for 2009. The proposed regulation does

not require facilities to create a new emissions inventory. Instead, facilities would provide their 2009 emissions of GHG, criteria pollutants, and TACs that were reported for the Mandatory GHG Reporting Regulation (for GHG) and Air Pollution Control and Air Quality Management Districts (local district) reporting programs (for criteria pollutants and TACs). The GHG data reported will be validated by a third party verification process that is required by the Mandatory GHG Reporting Regulation. The criteria pollutant and TAC emission data will be validated by ARB and local district staff as part of their existing emission data management programs.

In the second element, facility operators would be required to conduct a comprehensive assessment of potential energy efficiency improvement projects that are possible at the facility and the associated impacts that would occur if the projects were implemented. The operators would include a description of each project, the types of processes and equipment involved, preliminary estimates for costs, timing, status (if the project is being implemented), project life, energy and cost savings, potential emission reductions (GHG, criteria, and toxics), district permitting impacts, and other project related impacts. The methodology for quantifying the estimated emission reductions would also be required to be specified.

For the last element, facility operators would be required to submit a report (Assessment Report) containing the facility's energy consumption and emissions analysis and the energy efficiency improvement analysis. The Assessment Report would be submitted to ARB by the end of 2011, and would then undergo an internal ARB review process to determine its completeness and validity. If a report is deemed to be incomplete, then a new assessment, conducted by an approved third party assessor, may be required.[3] Once staff has completed review of the submitted reports, they will be made available to the public on ARB's Climate Change website. We anticipate that public release would occur in April 2012.

6. What is the timeline for implementing the proposed regulation?

Staff expects to begin implementing the proposed regulation in 2011, with the facility reports due to be submitted to ARB by the end of that year. Staff plans to summarize the findings from the Assessment Reports for each sector and release the information in a public document in mid-2012. Table 1 below shows the expected timeline of key elements in implementing the proposed regulation.

[3] The Executive Officer will approve the third party assessor selected by the facility operator upon demonstration that the third party assessor is qualified to effectively conduct the assessment and that there is no conflict of interest.

Table 1: Timeline for Proposed Energy Efficiency Assessment Regulation Implementation

Action	Proposed Dates
Assessment Reports Due to ARB	December 15, 2011
ARB Publishes Reports Online	April 30, 2012
ARB Draft Report – Preliminary Findings and Recommendations	June 30, 2012

7. What are the benefits of the proposed regulation?

In order to reach the State's mandated 2020 GHG emission limit, all potential emission reduction opportunities must be assessed. The proposed regulation will provide ARB with a comprehensive list of actions that potentially could be taken to reduce emissions from the largest stationary GHG sources. This information will be used to inform GHG, criteria pollutant, and TAC emission control program development and implementation. It will help identify a range of possible approaches (e.g., voluntary action, incentive-based, and State or local regulations) to maximize GHG emission reductions and co-benefits. This will be particularly important as we work to address direct, indirect, and cumulative emissions impacts of other GHG programs such as a California cap-and-trade program. The information will be helpful to assess localized impacts in communities that are already adversely impacted by air pollution. The information will also provide valuable data which ARB, local districts, and the public can use to identify opportunities for achieving further reductions in criteria and toxic emissions.

8. How will the proposed regulation be implemented?

Staff will work directly with the facilities subject to the proposed regulation to provide real-time guidance and feedback throughout the assessment analysis and reporting process. Teams, consisting of ARB staff most familiar with each industrial sector, will work directly with the facility operators as they conduct the assessment. These same ARB staff members will review the facility assessment reports for completeness, validate the information provided, and obtain additional information from the facility where necessary. Having staff involved throughout the analysis and reporting process will allow ARB to provide guidance to facility operators on implementation issues and will help to ensure consistency in the reports. This will speed up the review process as well, since staff will be able to more quickly resolve questions and interpretation issues.

9. Will the information from the assessment reports be made available to the public?

Yes. ARB staff believes it is critical that the information collected be publicly available, particularly to those communities that are located near the facilities. In developing the proposed regulation, ARB staff's goal was to require information that is preliminary but comprehensive enough to guide future decision making. We believe that this can be

accomplished without sources having to provide confidential business information. Since staff would be working with the facility operators throughout the analysis and reporting process, issues regarding confidentiality can be addressed early on, prior to report submittal, to ensure that the information provided to ARB can be directly released to the public. As such, the proposed regulation includes a provision requiring the ARB to publish the completed assessment reports on ARB's website by April 30, 2012.

10. What are the economic impacts of the proposed regulation?

ARB staff estimates that the total cost of the proposed regulation to affected businesses would be approximately $14 million over a period of about 16 to 18 months. A summary of the expected costs by grouped industrial sectors is provided below in Table 2. As can be seen, the majority of the costs will be borne by refineries and oil and gas extraction facilities, which account for about $10 million or 75 percent of the total costs.

Table 2: Estimated Facility Costs and Total Costs for Compliance with the Proposed Regulation

Industrial Sectors	Number of Facilities	Estimated Cost per Facility ($2009)	Total Costs
Electricity Generating Facilities and Hydrogen Plants	21	$78,000	$1,638,000
Cement and Mineral Plants	11	$175,000	$1,925,000
Petroleum Refineries and Oil & Gas Extraction and Transmission	24	$425,000	$10,200,000
Totals	56	N/A	$13,763,000

Overall, the vast majority of the affected businesses are large businesses, many owned by multi-national corporations, and therefore we do not expect their profitability to be adversely impacted. As a result, we do not expect a noticeable change in employment, business creation, expansion, or elimination, or business competitiveness in California. We also found no adverse economic impacts to any local or federal agencies. ARB will incur minimum costs to administer the proposed regulation. These costs would be met with existing resources. No other State agencies will be affected.

No job or business losses are anticipated in California due to the regulation. However, there may be a small increase in the amount of work for consultants in the event facility operators out-source the work needed to fulfill the requirements in the proposed regulation.

11. How does the regulation support the greenhouse gas emission reduction goals?

AB 32 directed the ARB to prepare a Scoping Plan identifying specific actions that could be taken to reduce GHG emissions. The proposed regulation is one of the many measures presented in the Scoping Plan. Implementing the proposed measure will fulfill the goal of the Scoping Plan measure and will acquire the necessary data needed to further pursue achieving GHG emission reductions from the largest GHG emitting facilities in the State. The proposed regulation will also help inform sources and the public of criteria pollutant and toxic air contaminant emissions co-benefits.

12. Why doesn't the proposed regulation require third-party assessments?

Staff has evaluated this option and determined that requiring a facility-conducted assessment is the best approach. Staff believes that it would result in a better product because the equipment and process experts that operate each facility would be conducting the assessment. Given the complexity of many of these sources, it would be difficult to find a third-party assessor with sufficient expertise to conduct the detailed assessment that is required. Additionally, a self-assessment would reduce the amount of time required for rule development and implementation by at least one year by not having to establish a third-party assessor accreditation program. Finally, it would reduce the cost to the regulated community. However, the proposed regulation includes a third-party assessment back-stop, so that if ARB finds that the Assessment Report is unacceptable, ARB could require the facility to conduct a third-party assessment.

13. Why doesn't the proposed regulation require implementation of any identified energy efficiency improvement projects?

Staff's proposal does not include a requirement to implement the improvement projects that are indentified in the Assessment Reports for several important reasons. First, the requirement would likely narrow the focus of the energy efficiency improvement analysis instead of providing a full range of possible improvements that can be made for both near-term and long-term emission reductions. Second, a cost-effectiveness or feasibility trigger would need to be established, which is not only difficult to do prior to determining what opportunities are available, but could result in an inadequate consideration of projects that actually have greater co-benefits for other pollutants. Lastly, requiring implementation of the identified improvement projects within the scope of this proposed regulation would not allow the public to participate in the process of determining the priority of the projects, since project selection would be pre-programmed and done prior to data collection.

14. What is the relationship between the proposed regulation and a possible cap-and-trade regulation?

Any cap-and-trade program would likely rely on data collected by the Mandatory GHG Reporting Regulation to determine the inclusion of an industrial source. We anticipate

that most, if not all, of the approximately 60 stationary source facilities required to comply with the proposed regulation will also have GHG emissions exceeding the 0.25 $MMTCO_2e$ eligibility threshold staff has proposed in the preliminary draft regulation of the cap-and-trade program (ARB,2009). As such, these sources will be required to manage their GHG emissions under an aggregate declining emissions cap that supports achieving the 2020 emissions target established by AB 32. To meet the declining cap, these sources will either have to reduce emissions onsite or through the purchase of additional allowances and/or offsets. The information developed to comply with the proposed Energy Efficiency Assessment regulation will be critical for sources to identify and determine how best to achieve GHG emission reductions needed to meet the cap and, at the same time, consider criteria pollutant and TAC co-benefits.

15. What existing programs are available to improve energy efficiency in the industrial sector and why didn't ARB staff rely on those programs?

Several programs are currently available that provide industrial facilities with information, tools, and opportunities for improving energy efficiency. The federal Department of Energy's Industrial Technologies Program (DOE ITP) works to improve industrial energy intensity through innovative energy efficiency technologies and practices. They provide software tools, industry best practices information, training to certify energy experts in specific energy intensive processes, and assessment programs. Their latest program, Save Energy Now, focuses on implementation of identified improvement opportunities, and is available for qualified large industrial facilities. (DOE, 2010)

ENERGY STAR is a joint program of the U.S. Environmental Protection Agency and the U.S. Department of Energy that promotes the use of energy efficient products and practices. (U.S. EPA, 2010) ENERGY STAR is creating partnerships with industrial plants to offer a proven energy management strategy that helps in measuring current energy performance, setting goals, tracking savings, and rewarding improvements. The approach is based on the successful energy management practices of over 1,600 commercial and industrial organizations. The *Guidelines for Energy Management* outlines the strategy to set performance goals, create and implement action plans, assess performance and progress, and recognize an organization's achievements. To learn more about the Energy Star Program for buildings and plants visit the following website: http://www.energystar.gov/index.cfm?c=industry.bus_industry

The California Energy Commission (CEC) administers an industrial process energy efficiency program where inspectors, certified through the DOE ITP, conduct free industrial energy efficiency assessments, funded by the Department of Energy. The assessments identify improvements that have a one- to three-year payback period and quantify the energy savings and GHG emission reductions associated with implementation. (CEC, 2009)

Energy efficiency improvement incentive programs for industrial facilities are frequently available through public utility agencies as well. The utilities often work with a facility to

identify energy savings opportunities, and implementing the project(s) can result in a monetary rebate award.

Other programs are also available that help to fund and support research and development of emerging technologies that improve energy efficiency. The Advanced Technologies Program (ATP) of the National Institute of Standards and Technology is one such program that invests in commercial research projects to foster new, innovative technologies. (ATP, 2010) Industrial facilities of all sizes compete equally for ATP cost-sharing to develop improvements in industrial processes that will benefit the industry as a whole, not just the specific facility. While the ATP does not focus solely on energy efficiency, it is one of the program areas that it supports.

Staff did not rely solely on these programs to provide the information required in the proposed regulation because none of the existing programs are comprehensive enough to result in a full assessment of the energy efficiency and emission reductions opportunities that exist at industrial facilities, which is crucial in meeting the goals of the proposed regulation. Moreover, most of these programs focus on energy efficiency improvements and have not looked at the impact of these actions on criteria pollutant and toxic air contaminant emissions. Generally, these programs are focused on specific processes and short payback periods as opposed to providing a full range of opportunities for both the near-term and long-term. However, the proposed regulation does allow the data acquired from participation in these types of programs to be used in order to meet applicable portions of the proposed regulation where appropriate.

16. What future activities are planned?

Once the Assessment Report review and approval process is completed, staff will develop a draft report with preliminary findings and recommendations. This draft report will be used as a starting point for discussion with all stakeholders on what actions and approaches could be taken to maximize GHG, criteria pollutant, and toxic air contaminant emission reductions. We expect the draft report to be publicly available in mid-2012. Staff will then conduct public meetings to discuss the draft report and seek input from the public on actions and approaches (e.g., voluntary action, incentive-based, and State or local regulations) to maximize GHG emission reductions and co-benefits. Additionally, criteria pollutant and toxic air contaminant emission reduction opportunities identified in the Assessment Reports will be evaluated for their relevance to be included in local air district programs and other ARB emission reduction programs.

17. What is staff's recommendation?

Staff recommends the Board approve the proposed regulation presented in this report (Appendix A). The regulation will support ARB's GHG emission reduction objectives and fulfill the goals of the Scoping Plan measure by providing a comprehensive list of feasible actions that can be taken to reduce GHG emissions from the largest stationary industrial facilities in the State. Adopting the proposed regulation will also support other emission reduction programs for criteria pollutants and toxic air contaminants, providing

information necessary to carry out the Board's responsibilities under State law. It will also provide valuable information to the public about facilities in their communities.

- This page is intentionally blank -

I. INTRODUCTION

This report with associated attachments represents the Initial Statement of Reasons (ISOR or Staff Report) for Proposed Rulemaking required by the California Administrative Procedures Act. In this report, the Air Resources Board (ARB or Board) staff presents the *Proposed Regulation for Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities* (Energy Efficiency Assessment Regulation or proposed regulation). The Staff Report provides information on how the proposed regulation was developed and what it requires, the industrial sectors that will be subject to the proposed regulation, and information on the environmental and economic impacts from the proposal. In this chapter, the ARB staff provides an overview of the proposed regulation ("proposal") and discusses the regulatory authority ARB has to adopt the proposed regulation. We also discuss other regulatory activities and programs that impact the industrial sectors that will be subject to the proposed regulation, and the public outreach process used to include all interested stakeholders in developing the proposed regulation.

A. Overview

The California Global Warming Solutions Act of 2006 (Act or AB 32) (Assembly Bill 32, Ch. 488, Stats 2006) created a comprehensive multi-year program to reduce greenhouse gas (GHG) emissions in California. The Act requires ARB to create and implement measures needed to reduce current GHG emissions to 1990 levels by 2020. In addition, on December 11, 2008, the Board approved a Climate Change Scoping Plan (Scoping Plan) describing California's strategy for meeting the GHG emissions reductions required by AB 32. One of the measures contained within the Scoping Plan requires a one-time assessment of large industrial sources to determine the potential GHG emission reduction opportunities, as well opportunities to reduce emissions of criteria pollutants and toxic air contaminants (TACs).

The proposed Energy Efficiency Assessment Regulation is designed to meet the requirements identified in the Scoping Plan. Specifically, it will apply to industrial facilities emitting GHG emissions of at least 0.5 $MMTCO_2e$ each annually (e.g. oil and gas production facilities, electricity producers, mineral production, and hydrogen producers) and any cement plants or transportation fuel refineries that emit GHG emissions of at least 0.25 $MMTCO_2e$ each annually. The proposed regulation will require that each facility conduct a one-time assessment of their energy consumption, emissions, and potential for energy efficiency improvements that potentially could result in GHG emission reductions, with additional quantification of associated reductions in criteria pollutants and TACs.

B. Primary Enabling Legislation

In June 2005, Governor Arnold Schwarzenegger signed Executive Order S-3-05, which established targets for reducing GHG emissions in California. The Executive Order

targets GHG emissions to be reduced to 2000 levels by 2010, to 1990 levels by 2020, and finally to 80 percent below 1990 levels by 2050. In 2006, the Governor signed AB 32, which established the 2020 GHG emission reduction goal in State law (Health and Safety Code (HSC) § 38500 et seq.) and made the ARB responsible for monitoring and reducing GHG emissions.

Among the provisions, AB 32 required the Board, by January 1, 2009, to design and adopt an overall plan to reduce GHG emissions to 1990 levels by 2020. On December 11, 2008, the Board approved a Climate Change Scoping Plan (Scoping Plan) describing California's strategy for meeting the GHG emissions reductions required by AB 32.

This proposed measure was identified in the Scoping Plan as a GHG reduction measure. The Scoping Plan states that rulemaking on the Energy Efficiency Assessment Regulation was to be initiated in 2010, effective by 2012, with results available to ARB at least by 2013. (ARB, 2008) State law also provides ARB with general authority to require monitoring and reporting of emissions of air pollutants or air contaminants other than GHGs.

C. Statutory Requirements

AB 32 contains provisions in HSC sections 38510 and 38530 that designate ARB as the state agency to monitor and regulate GHG emissions, and that require ARB to adopt regulations requiring reporting and verification of GHGs, the program for which ARB is to monitor and enforce. ARB is to periodically review and update these requirements as necessary and to make reasonable efforts to promote consistency with other GHG reporting requirements. Here ARB is promoting consistency by allowing affected sources to use the same inventory generated for the Mandatory GHG Reporting Regulation.

In addition, longstanding authority pre-dating AB 32 provides ARB with comprehensive authority to require sources of air pollution to submit information to determine the amount of their emissions. See HSC sections 39600, 39601, and 41511.

AB 32 also contains provisions in HSC sections 38560 and 38562 that apply to regulations adopted consistent with the Scoping Plan. Those criteria are summarized below in italics along with staff's assessment as to why the proposed regulatory action complies with the specific criteria or does not apply. Several of the AB 32 requirements are not applicable to this proposed regulation because it only requires a one-time report and does not require any emission reduction actions.

The State Board shall adopt rules and regulations in an open public process to achieve the *maximum technologically feasible and cost-effective greenhouse gas emission reduction from sources or categories of sources.*

The proposed regulation was developed in consultation with affected industry, environmental group representatives, other interested parties, and the public. The proposed regulation was developed in an open process including three public workshops, industry-specific consultation meetings, staff visits to affected facilities, consultation meetings with environmental representatives, and numerous telephone conferences. Draft regulatory concepts were first presented in June 2009 and modified through discussion and feedback during this process.

Design the regulations, including distribution of emissions allowance where appropriate, in a manner that is equitable, seeks to minimize costs and maximize the total benefits to California, and encourages early action to reduce greenhouse gas emissions.

This requirement is not applicable to this proposed rulemaking. The proposed regulation does not require emission reductions, but rather is designed to gather information about the potential GHG emission reduction opportunities, and associated criteria pollutant and TAC co-benefits.

Ensure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities.

The proposed regulation requires data gathering and not emission reduction actions. However, the data gathered will provide valuable information to assist in designing future requirements that ensure no disproportionate impact low-income communities.

Ensure that entities that have voluntarily reduced their greenhouse gas emissions prior to the implementation of this section receive appropriate credit for early voluntary reductions.

Since the proposed regulation does not require any emission reduction actions, receiving emission reduction credits for early action is not necessary. However, the regulation does provide for sources to report recent GHG emission reduction actions that they have taken or plan to take.

Ensure that activities undertaken pursuant to the regulations complement and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions.

The proposed regulation will not interfere with efforts to reduce criteria pollutants and TACs. In fact, it will provide valuable information about the potential criteria pollutant and TAC co-benefits associated with specific actions to reduce GHG emissions and improve energy efficiency.

Consider cost-effectiveness of these regulations.

The proposed regulation does not require any actions to reduce emissions, nor claim any emission reductions associated with implementation of the regulation. Therefore, a traditional cost-effective analysis is not appropriate. We have instead evaluated the cost of complying with the proposed regulation in the context of the revenue generated by the companies that would have to comply with the proposed regulation. Overall, the majority of the companies are large businesses, many owned by multi-national companies with significant annual revenue. None are small businesses. Based on our analysis, which is provided in Chapter V of this report, we do not expect any adverse impacts on the profitability or competitiveness of the businesses that will be affected by the proposed regulation.

Consider overall societal benefits, including reductions in other air pollutants, diversification of energy sources, and other benefits to the economy, environment, and public health.

The proposed regulation is not expected to reduce emissions in a quantifiable way, but rather it is designed to gather information about the potential GHG emission reduction opportunities, as well as associated criteria pollutant and TAC co-benefits. Thus, an analysis on societal benefits is not applicable.

Minimize the administrative burden of implementing and complying with these regulations.

The administrative burden of complying with the proposed regulation has been minimized to the extent possible by providing flexibility in conducting the assessment and ensuring that the reporting requirements are consistent with those contained in ARB's Mandatory GHG Reporting Regulation (17 CCR Sections 95100, *et seq.*). The proposed regulation allows sources to either conduct the assessment with their own staff or to hire a third party. Industry has commented extensively that using their experienced staff will be far less burdensome, and less costly, than hiring a third-party reviewer. To minimize the reporting burden, staff provides that the data reported for criteria pollutant and TAC emissions is the same data that are collected to meet ARB and local district criteria pollutant and TAC emission inventory requirements. Staff also allows for energy efficiency information collected as part of other programs (e.g. Department of Energy, California Energy Commission, National Institute of Standards and Technology) to be used to meet applicable portions of the proposed regulation where appropriate. Finally, the actions required by the proposed regulation are, in large measure, an action that will benefit these facilities under the cap-and-trade requirements that are currently under development by ARB staff.

Minimize leakage

This requirement is not applicable to this proposed rulemaking.

Consider the significance of the contribution of each source or category of sources to statewide emissions of greenhouse gases.

The proposed regulation will affect stationary industrial facilities that are significant sources of GHG emissions in the California. We estimate that the facilities that will be subject to the proposed regulation account for about 45 percent of the GHG emissions from the industrial sector in California.

The greenhouse gas emission reductions achieved are real, permanent, quantifiable, verifiable, and enforceable by the State board.

The reduction is in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur.

If applicable, the greenhouse gas emission reduction occurs over the same time period and is equivalent in amount to any direct emission reduction required pursuant to this division.

The above three requirements are not applicable since the proposed regulation does not directly require any actions to reduce emissions, nor claim any emission reductions associated with implementation of the regulation.

The State board shall rely upon the best economic and scientific information and its assessment of existing and projected technological capabilities when adopting the regulations required by the law.

ARB staff used the best available economic and scientific information available to develop the proposed regulation. Staff collected information on all potential regulated entities and reviewed the available literature for other sources of economic and scientific information. Staff relied upon data obtained through ARB's Mandatory GHG Reporting Regulation, the U.S. EPA, industry organizations, trade associations, as well as academic institutions.

D. Existing Regulations and Programs

This section discusses other related regulations and programs that are applicable to the industrial sectors that will be subject to the proposal. It is not intended to be an exhaustive listing; rather, we have highlighted the key programs that are interrelated to the proposed regulation.

Greenhouse Gas Mandatory Reporting Regulation

ARB developed the Mandatory GHG Reporting Regulation under the direction of AB 32. The Board approved the Mandatory GHG Reporting Regulation in December 2007. The regulation appears in sections 95100-95133 of title 17, California Code of Regulations. The Mandatory GHG Reporting Regulation requires facilities to report their annual GHG emissions beginning in 2009 and every year thereafter. The industrial

sectors that must report their emissions are: cement plants, oil refineries, hydrogen plants, electricity generating facilities, cogeneration facilities, other large stationary combustion sources, and electricity retail providers and marketers. All of the facilities that will be subject to the proposed Energy Efficiency Assessment Regulation must also report their emissions to the Mandatory GHG Reporting Program.

The results of the Mandatory GHG Reporting Regulation are intended to provide information that assists with the development and implementation of strategies to reduce the emissions that cause climate change. Under the Act, the Mandatory GHG Reporting Regulation must: begin reporting with the most significant GHG emissions sources, use rigorous and consistent emission accounting methods, and provide for verification of reported emissions data. Additional information, including staff contact information, is available at ARB's Climate Change website, http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

Criteria Pollutant Control Program

Under HSC section 40910 (Stats. 1988, ch. 1568, Sec. 11, amended by Stats. 2000, Ch. 729, Sec. 9) the local districts are required to achieve and maintain the state Ambient Air Quality Standards for ozone, carbon monoxide, sulfur dioxide, and nitrogen dioxide by the earliest practicable date. To achieve this objective, the local districts develop attainment plans and regulations with the consideration of the full spectrum of emission sources.

Under HSC section 40701 (Stats. 1975, Ch. 957, amended by Stats. 1990, Ch. 1034, Sec. 1) the local districts have the power to require any owner or operator of any air pollution emission source, except a noncommercial vehicular source, to provide 1) a description of the source and 2) disclosure of the data necessary to estimate the emissions of pollutants for which ambient air quality standards have been adopted, or their precursor pollutants, so that the full spectrum of emission sources can be addressed equitably pursuant to Section 40910. See also section 41511.

California Air Toxics "Hot Spots" Program

The Air Toxics "Hot Spots" Information and Assessment Program was established by AB 2588 (Stats. 1987, ch. 1252) and is set forth in HSC sections 44300-44393. The goals of the "Hot Spots" program are to collect emission data, identify facilities having localized impacts, ascertain health risks, notify nearby residents of significant risks, and require that owners of significant-risk facilities to reduce their risks below the level of significance.

The "Hot Spots" program requires that emissions of TACs from stationary source facilities be quantified and compiled into an inventory according to criteria and guidelines which are specified in the Emission Inventory Criteria and Guidelines (see California Code of Regulations, Title 17, sections 93300-93355). These emission

inventories must be submitted to their local district within 180 days of the approval of their emission inventory plan.

Cap-and-Trade Program

Under AB 32, California must reduce GHG emissions to 1990 levels by 2020. The AB 32 Scoping Plan calls for a California cap-and-trade program that links with other regional partner jurisdictions in the Western Climate Initiative (WCI) to create a regional market system. As adopted in the Scoping Plan, the cap-and-trade program would establish a cap covering about 85 percent of the State's GHG emissions and allow trading to ensure cost-effective emissions reductions. The California cap-and-trade program is still under development. (ARB, 2009) Per AB 32, the cap-and-trade program is to be adopted by January 1, 2011. ARB staff is scheduled to bring a cap-and-trade program to the Board for their review in late 2010.

Energy Efficiency Programs

Several programs are currently available to provide industrial facilities with information, tools, and opportunities for improving energy efficiency. Some of these are briefly described below.

Department of Energy's Industrial Technologies Program: The federal Department of Energy's (DOE) Industrial Technologies Program (ITP) leads national efforts to improve industrial energy efficiency and environmental performance. Under their BestPractices© program, ITP works with companies to implement energy management practices by providing a number of resources for corporate executives, plant managers, technical staff, and the general public. The BestPractices© program provides software tools, industry best practices information, training to certify energy experts in specific energy intensive processes, and assessment programs. ITP's latest program, *Save Energy Now*, is a national initiative that aims to drive a reduction of 25% or more in industrial energy intensity in 10 years. Under this program, any company can partner with ITP to participate in a no-cost onsite plant assessment to help improve energy efficiency and increase productivity. The ITP website provides a list of large plants that have participated in a *Save Energy Now* assessment with their assessment reports. Similarly, case studies are available from the BestPractices© program the shows the results of a plant-wide assessment or demonstration project. (DOE, 2010)

ENERGY STAR is a joint program of the U.S. Environmental Protection Agency and the U.S. Department of Energy that promotes the use of energy efficient products and practices. (U.S. EPA, 2010) ENERGY STAR is creating partnerships with industrial plants to offer a proven energy management strategy that helps in measuring current energy performance, setting goals, tracking savings, and rewarding improvements. The approach is based on the successful energy management practices of over 1,600 commercial and industrial organizations. The *Guidelines for Energy Management* outlines the strategy to set performance goals, create and implement action plans, assess performance and progress, and recognize an organization's achievements. To

learn more about the Energy Star Program for buildings and plants visit the following website: http://www.energystar.gov/index.cfm?c=industry.bus_industry

California Energy Commission: The California Energy Commission (CEC) administers an industrial process energy efficiency program where inspectors, certified through the DOE ITP, conduct free industrial energy efficiency assessments, funded by the Department of Energy. The assessments look at process furnaces, boiler and steam distribution, compressed air, fans, pumps, motor systems, and can include heating, ventilation and air conditioning (HVAC), refrigeration, and lighting systems. After the assessment, the plant management is given specific energy-saving recommendations. Often the CEC inspectors are able to identify improvements that have a one- to three-year payback period and quantify the energy savings and greenhouse gas emission reductions associated with implementation. The CEC also offers *BestPractices*© *Workshops* which train plant operators in more efficient operation of energy-consuming equipment and systems. (CEC, 2009)

Public Utility Agencies: Energy efficiency improvement incentive programs for industrial facilities are frequently available through public utility agencies. The utilities often work with a facility to identify energy savings opportunities, and implementing the project(s) can result in a monetary rebate award. For example, Pacific Gas and Electric Company (PG&E) is currently offering a free energy analysis or integrated energy Assessment for industrial facilities. Under this program, a technical specialist will conduct an assessment to analyze current energy use and identify savings opportunities. (PG&E, 2010)

Advanced Technologies Program: Other programs are also available that help to fund and support research and development of emerging technologies that improve energy efficiency. The Advanced Technologies Program (ATP) of the National Institute of Standards and Technology is one such program that invests in commercial research projects to foster new, innovative technologies (ATP, 2010). Industrial facilities of all sizes compete equally with other companies for ATP cost-sharing to develop improvements in industrial processes that will benefit the industry as a whole, not just the specific facility. While the ATP does not focus solely on energy efficiency, energy efficiency is one of the program areas for which the provide support.

E. Development of the Proposed Regulation

The proposed regulation was developed in consultation with affected industry, environmental group representatives, other interested parties, and the public. The proposed regulation was developed in an open process including three public workshops, industry-specific consultation meetings, staff visits to affected facilities, consultation meetings with environmental representatives, and numerous telephone conferences, calls, and emails. The regulatory development process spanned over 18 months and included several meetings with industry-specific working groups.

To support regulatory development, ARB staff visited 10 facilities representative of the facilities affected by the proposed regulation and conducted numerous conference calls. During these site visits and conference calls, the staff learned the basic processes of the facilities, how energy efficiency is measured, and what energy efficiency projects have already been completed.

ARB staff has also participated in numerous individual meetings with various stakeholders, supported by individual telephone calls.

ARB staff held three public workshops to discuss the development of the draft regulation and to gather information from industry and environmental representatives on the possibilities and difficulties of preparing an energy assessment.

The announcements and meeting materials for the workshops were posted on the ARB website and distributed through a list serve that included over 6,400 recipients. All of the meetings were audio and video webcast on the California Environmental Protection Agency's public broadcast site. The dates of the workshops and the materials presented at each workshop are available on the following ARB website: http://www.arb.ca.gov/cc/energyaudits/energyaudits.htm .

- This page is intentionally blank -

II. SECTORS AND FACILITIES

California is home to some of the largest industrial facilities in the country. The industrial sector consumes about 25 percent of the energy used in the State, resulting in GHG emissions of about 160 $MMTCO_2e$ in 2008. (EIA, 2010) (ARB, 2010a) The proposed regulation will apply to the largest industrial facilities in the State. These facilities are responsible for about 45 percent of the GHG emissions from all industrial sources in California. Approximately 60 facilities in five industrial sectors would be subject to the proposed regulation based on applicability criteria in the proposed regulation and the 2008 calendar year GHG emissions data reported to the ARB pursuant to the Mandatory GHG Reporting Regulation.[4] The sectors include petroleum refineries (18 facilities), oil and gas extraction and transmission facilities (6 facilities), electricity generating facilities (18 facilities), cement plants and mineral plants (11 facilities), and hydrogen plants (3 facilities). A listing of the facilities and the 2008 GHG emissions reported under the Mandatory GHG Reporting Regulation is provided in Table 3.

Table 3: Facilities in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation and Their 2008 GHG Emissions

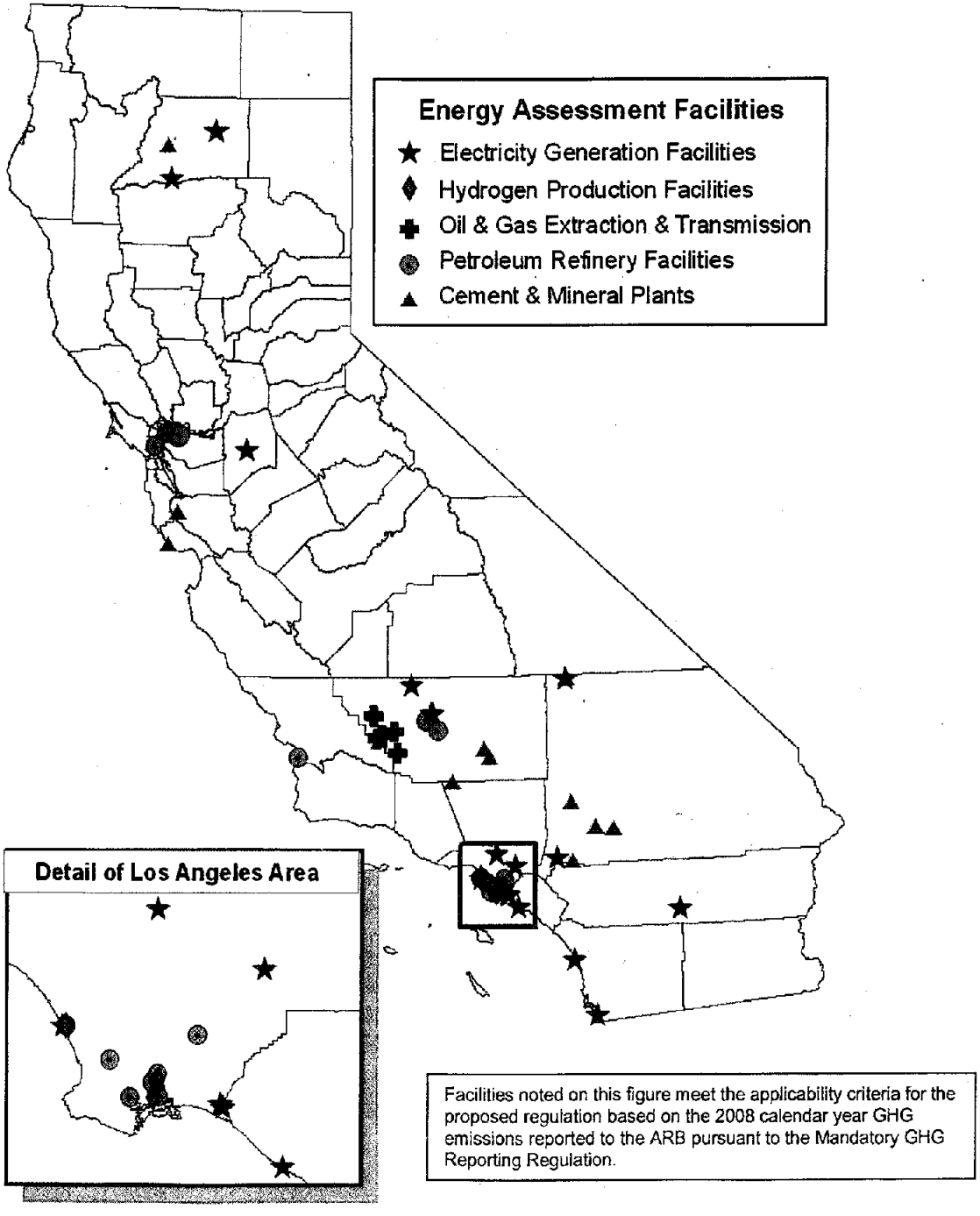
Air Basin	Industrial Sector	2008 GHG Emissions $MMTCO_2e$
	Cement and Mineral Plants	
Mojave Desert	Cemex - Black Mountain Quarry	2.2
	Mitsubishi Cement 2000	1.1
	Searles Valley Minerals	1.7
	TXI Riverside Cement (Oro Grande Plant)	0.9
North Central Coast	Cemex - Cement Plant Davenport	0.4
Sacramento Valley	Lehigh Southwest Cement Co - Redding	0.4
San Francisco Bay Area	Lehigh Southwest Cement Company - Cupertino	0.7
San Joaquin Valley	CalPortland Company, Mojave Plant	1.2
	Lehigh Southwest Cement Co. - Tehachapi	0.5
	National Cement Company – Lebec	0.7
South Coast	CalPortland Company, Colton Plant	0.5
	Hydrogen Plants	
South Coast	Air Liquide El Segundo Hydrogen Plant	0.7
South Coast	Air Products Carson Hydrogen Plant	0.6
South Coast	Air Products Wilmington Hydrogen Plant	0.7
	Electricity Generating Plants	
Mojave Desert	ACE Cogeneration	0.9
Sacramento Valley	Burney Forest Products (Co-Gen)	0.9
	Wheelabrator Shasta Energy Company	0.7
San Diego	Dynegy South Bay, LLC	0.6
San Diego	NRG Energy – Encina	0.7

[4] The proposed regulation applicability will be based on the 2009 calendar year GHG emission data submitted pursuant to the GHG Mandatory GHG Reporting Regulation. The actual number of facilities may be higher or lower than presented here.

Air Basin	Industrial Sector	2008 GHG Emissions $MMTCO_2e$
	Electricity Generating Plants Cont.	
San Joaquin Valley	Covanta Delano, Inc	0.5
	Kern River Cogeneration Company (Co-Gen)	0.8
	Midway-Sunset Cogeneration (Co-Gen)	1.2
	Stockton CoGen (Co-Gen)	0.6
	Sycamore Cogeneration Co (Co-Gen)	1.5
South Coast	AES Alamitos, LLC	1.4
	Aes Huntington Beach, Llc	0.9
	Colmac Energy, Inc. 92254	0.5
	Los Angeles Department of Water & Power-Haynes Generating Station	2.2
	Los Angeles Department of Water & Power-Scattergood Generating Station	0.9
	Los Angeles Department of Water & Power-Valley Generating Station	1.0
	Puente Hills Landfill, LA County Sanitation	0.6
	RRI Energy Etiwanda, Inc.	0.6
	Oil & Gas Extraction and Transmission	
San Joaquin Valley	Aera Energy LLC, Belridge, 93251	1.6
	Aera Energy LLC, MOCO, D&E, 93252	0.6
	Chevron U.S.A Inc - Cymric Asset, 93251	1.2
	Chevron U.S.A Inc - Midway Sunset Asset, 93225	0.9
	Occidental Of Elk Hills, Inc.	0.6
	Plains Exploration & Production Company - San Joaquin Heavy Oil Production Facility	0.9
	Petroleum Refineries	
San Francisco Bay Area	Chevron Products Company - Richmond Refinery, 94802	4.8
	Conoco Phillips Refining Company	1.9
	Shell Oil Products US	4.6
	Tesoro Refining and Marketing Company, 94553	2.7
	Valero Refining Company -California, Benicia Refinery and Benicia Asphalt Plant	2.8
San Joaquin Valley	Big West of California Bakersfield Refinery (Areas 1&2)	0.5
	Big West of California Bakersfield Refinery (Area 3)	0.1
	ConocoPhillips Santa Maria Refinery	0.2
	Kern Oil and Refining Company	0.2
	San Joaquin Refining Company	0.1
South Coast	BP West Coast Products LLC, Refinery	4.5
	Chevron Products Company - El Segundo Refinery, 90245	3.6
	ConocoPhillips Los Angeles Refinery Wilmington Plant	2.0
	ConocoPhillips Los Angeles Refinery, Carson Plant	0.9
	ExxonMobil Torrance Refinery	2.9
	Paramount Petroleum Corporation	0.2
	Tesoro Refining And Marketing Co. - LAR	1.6
	Ultramar Inc - Valero	1.0

As shown in Figure 3, these facilities are located throughout California with the largest numbers found in the Southern San Joaquin Valley and in and around Los Angeles and San Francisco.

Figure 3: Location of Facilities in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation



A. Sectors and Facilities Subject to the Proposed Regulation

The following discussion provides a short description of each industrial sector and the number and locations of the facilities. These estimates are based on the proposed regulation's applicability criteria and the 2008 calendar year GHG emissions data collected by ARB pursuant to the Mandatory GHG Reporting Regulation. As previously noted, the applicability for inclusion in the proposed regulation will be based on the 2009 calendar year GHG reporting; consequently, the estimated number of facilities and their emissions may change.

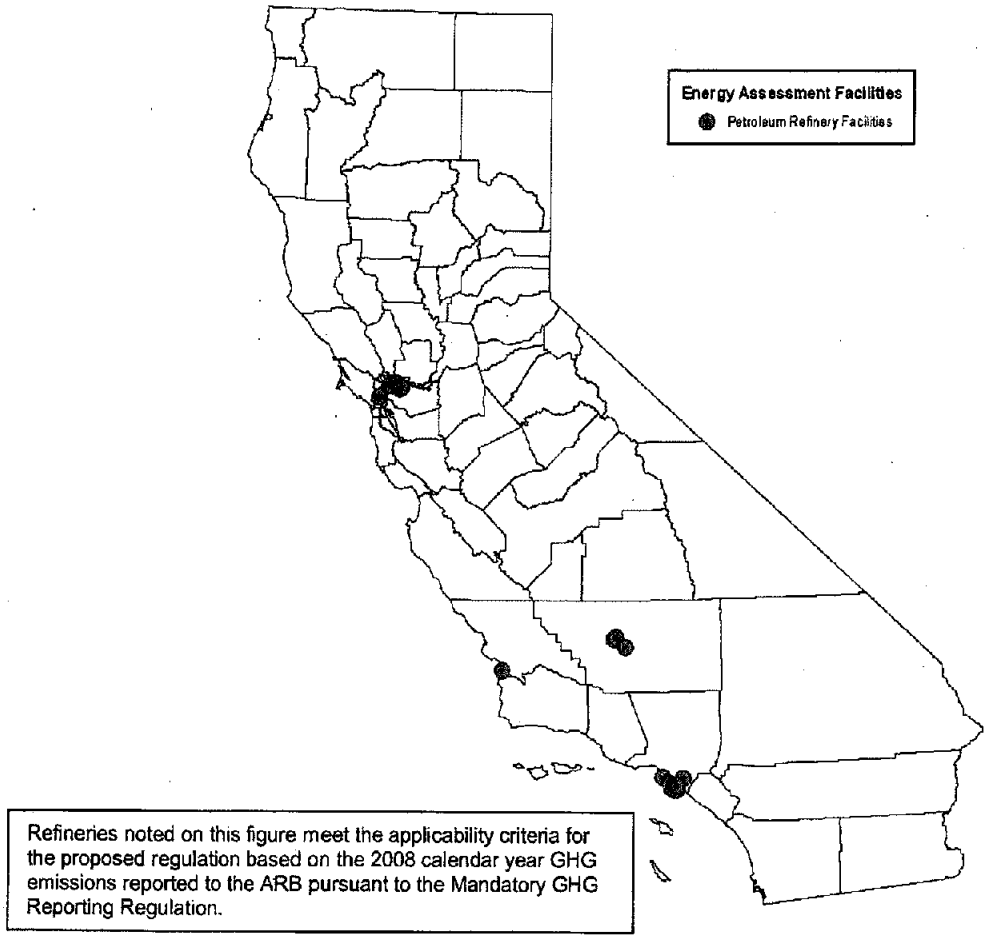
Petroleum Refineries

Currently, California refining capacity represents about 11 percent of the United States' (U.S.) crude distillation unit capacity. (Worrell and Galitsky, 2005) California refineries are more energy intensive operations than typical refineries in the rest of the U.S., primarily due to California's unique product mix and the additional hydrotreating necessary to produce that formulation. (Worrell and Galitsky, 2005) Additionally, the feedstock, or crude oil, available to California refineries has a lower specific gravity than crude oil available to other parts of the U.S. The lower the specific gravity, the more processing is required to produce high quality (i.e., "light") products. Another difference is that California refineries produce a larger fraction of lighter products, including reformulated transportation fuels (gasoline and diesel fuel), and fuels with lower sulfur content. (Worrell and Galitsky, 2004)

As presented earlier in Table 3, there are 18 petroleum refineries that may be subject to the proposed regulation. These refineries produce transportation fuels for release into commerce.

Figure 4 displays the location of the affected California refineries, the majority of which are located in the Southern San Joaquin Valley, Los Angeles and the San Francisco Bay Area.

Figure 4: Location of Petroleum Refineries in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation



Oil & Gas Extraction and Transmission Facilities

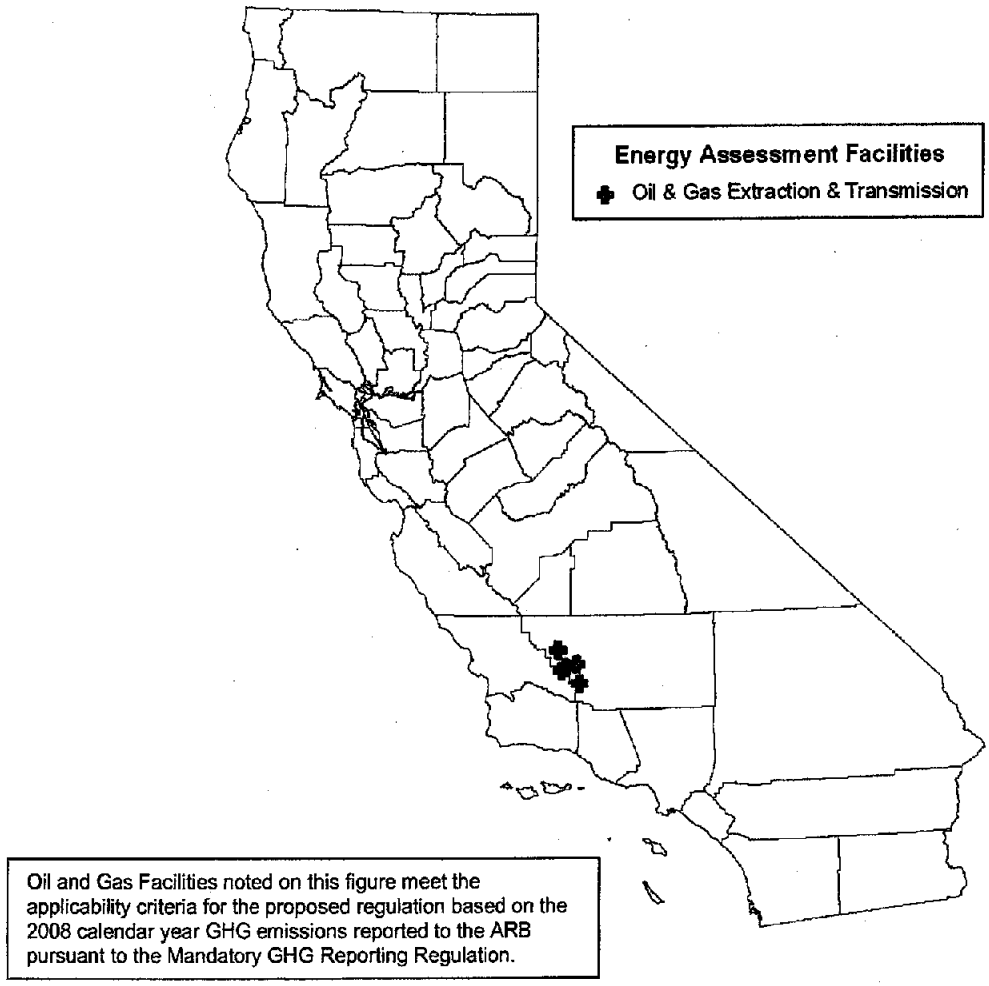
Oil and gas extraction and transmission facilities extract and transport crude oil and natural gas from below-ground oil and gas fields. The product extracted whether it is crude oil or natural gas, is predominantly sent to a refinery for processing. Oil and gas coming from the field is transported by pipelines, trucks, tankers, or barges to centralized processing and transmission facilities. California is considered to be one of the top crude oil producing states in the country. (Tribal Energy 2010)

Rock properties in different oil fields vary in porosity, permeability and heat transfer. The oil within different oil fields also varies in chemical makeup, the amount of dissolved gas, and the resultant viscosity. Therefore, wells in different fields require individual methods of extracting the oil or gas. Ideally, engineers design heating and pressure

maintenance systems for individual wells and groups of wells within a single oil field, depending on the particular rock and fluid properties.

As presented earlier in Table 3, there are six oil and gas extraction facilities that are expected to be affected by the proposed regulation. All of the six of these facilities are located in the southern San Joaquin Valley. The locations of the facilities are shown in Figure 5. There are no transmission facilities that are expected to be affected by the proposed regulation.

Figure 5: Location of Oil and Gas Facilities in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation



Electricity Generating Facilities (Power Plants)

ARB staff estimates there are about 34 electricity generating facilities that meet the 0.5 $MMTCO_2e$ GHG emissions threshold defined in the proposed regulation for applicability. However, the proposal exempts combined cycle power plants built after 1995, because turbine efficiency improved significantly after this time period. Staff believes these plants are the most energy-efficient facilities within the sector, and implementing the proposed regulation would not have benefits as great as other facility types. Therefore, 16 facilities would not be subject to the proposed requirements, leaving 18 facilities that would need to comply. The 18 electricity generating facilities are listed in Table 3 which is shown earlier in this chapter.

While fossil fuels such as coal, petroleum, and gas provide the energy needed to fuel most of the world's electricity generating facilities, most fossil-fueled electricity generating facilities in California currently burn natural gas due to its ready availability and clean burning nature. There are three main types of natural gas electricity generating facilities in California today, and each is described below.

Steam Turbine

In a steam turbine plant, fuel is burned and the hot combustion gas is used to produce superheated steam in a boiler. The superheated steam is expanded through a steam turbine providing power to drive a generator. Low pressure steam from the turbine is passed through a steam condenser and cooling tower to the environment. Steam turbine power plants use an older, less efficient technology compared with cogeneration and combined cycle power plants discussed below. There are 13 steam turbine electricity generating facilities that will be affected by the proposed regulation.

Cogeneration

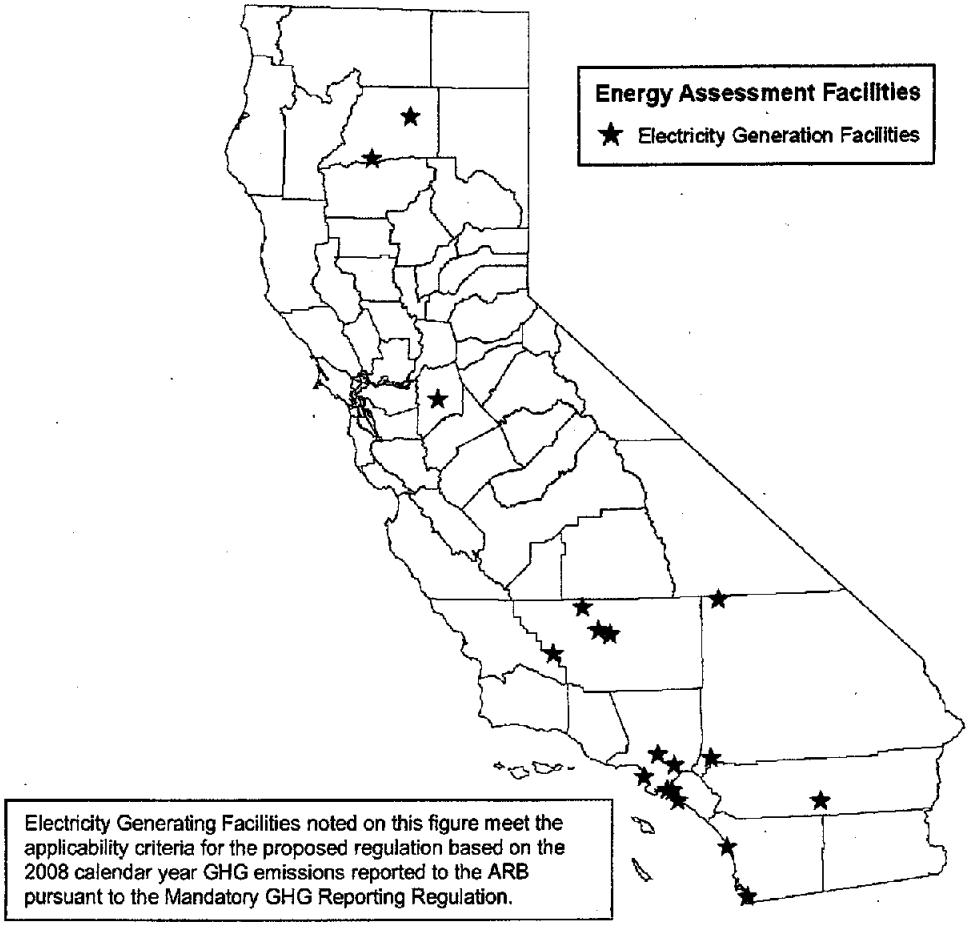
Cogeneration, also known as combined heat and power, produces both electricity and heat in a single process. By design, cogeneration plants recover energy lost in conventional steam turbine plants and provide it for other useful purposes. Such plants send the recovered steam to a host which uses it for things other than generating electricity (manufacturing, for example). Cogeneration plants are usually placed close to the host facility and are built to meet this demand as efficiently as possible. There are five cogeneration facilities that will be subject to the proposed regulation.

Combined Cycle

A combined-cycle gas turbine power plant consists of one or more gas turbine generators equipped with heat recovery steam generators (HRSGs) to capture heat from the gas turbine exhaust. Steam produced in the HRSGs powers steam turbine generators to produce additional electric power. Use of the otherwise wasted heat in the steam turbines results in high thermal efficiency compared to a conventional steam turbine power plant. Combined cycle plants currently entering service can convert

about 50 percent of the chemical energy of natural gas into electricity compared with the older steam turbine power plants which are about 30 percent efficient. (NPPC, 2002) As mentioned earlier, combined cycle electricity generating facilities that were built after 1995 are exempt from the proposed regulation.

Figure 6: Location of Electricity Generating Facilities in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation



Cement and Mineral Plants

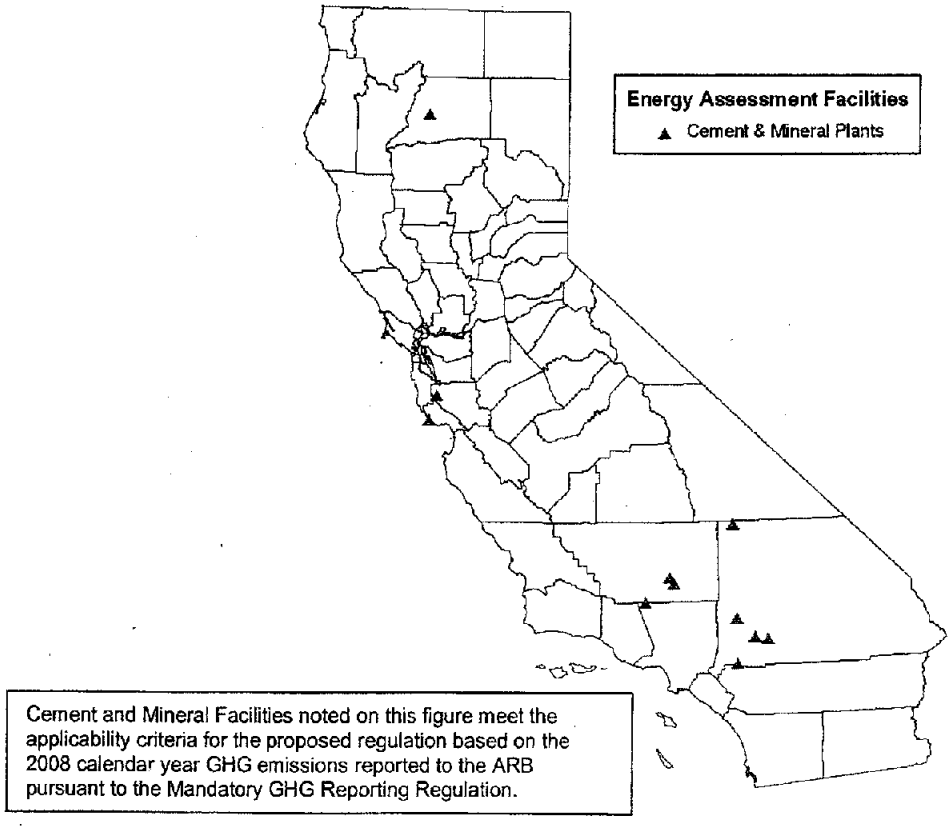
For the purposes of the proposed regulation, aggregate plants, sand and gravel plants, concrete plants, or asphalt plants are not considered cement plants. ARB staff estimates there are 11 cement and mineral plants that would be subject to the proposed Energy Efficiency Assessment Regulation. As shown in Table 3 presented earlier in this chapter, there are 10 cement plants and one mineral plant that will be affected by the proposed regulation.

Cement plants engage in the manufacturing of Portland, natural, masonry, pozzolanic, and other hydraulic cement products. Manufacturing cement is an energy-intensive process involving the grinding and mixing of raw materials, which are chemically altered through intense heat from a high-temperature kiln to form a compound with binding properties. (ARB GHG)

Mineral plants consist of mining operations involving the extraction of desired natural resources to be used as the raw, base materials for many of today's products. There is one mineral plant in California that is expected to be subject to the proposed regulation. This mineral plant mines and processes soda ash, sodium sulfate, and boron minerals. These minerals are then used in the manufacture of a wide variety of goods, including glass, ceramics, animal feed, paper products, and detergents. (SVM, 2009)

Figure 7 displays the 10 cement plants and one mineral plant that meet the proposed regulation applicability. As can be seen, most of the cement and mineral facilities are located in Southern California and 3 are located in Northern California.

Figure 7: Location of Cement and Mineral Facilities in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation



Hydrogen Plants

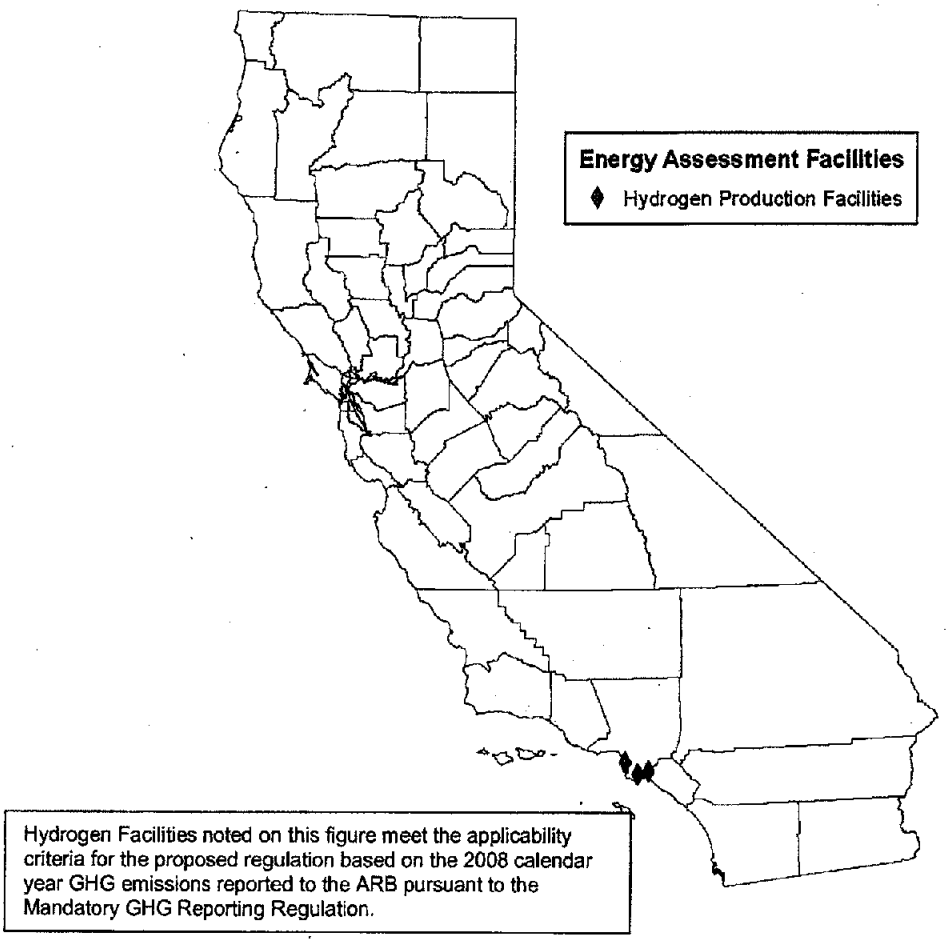
ARB staff estimates there are three "over the fence" hydrogen production facilities that would be subject to the proposed requirements.

Hydrogen production facilities primarily produce hydrogen for refineries that manufacture transportation fuels. Hydrogen is also used in the manufacture of ammonia-based nitrogen fertilizer and in fuel cells for transportation or power generation. (TCPA, 2008). Hydrogen is an essential element of petroleum refining operations. It is used in the hydrotreating process to remove sulfur from fuels and in the hydrocracking process to make lighter fuels from crude oil. Due to environmental pressure requiring removal of sulfur from petroleum products and the need to refine heavier crude oil, the demand for hydrogen continues to increase. (LBNL, 2005)

The hydrogen plant itself is typically located either within a refinery or adjacent to a refinery property as an "over the fence" hydrogen plant. The "over the fence" hydrogen plant may supply product to more than one refinery and be under separate operational control. The new modern hydrogen plants may generate and supply power in addition to hydrogen and steam. (Air Products, 2009) As in the Mandatory GHG Reporting Regulation, hydrogen production plants are addressed separately in the proposed regulation, and the company or organization having operational control of a facility is required to report emissions for the hydrogen facility. ARB staff estimates there are three "over the fence" hydrogen production facilities that would be subject to the proposed requirements.

Figure 8 displays the three hydrogen production facilities that meet the proposed regulation applicability criteria based on the 2008 calendar year GHG emissions data collected by ARB pursuant to the Mandatory GHG Reporting Regulation. The hydrogen facilities are located in the Los Angeles Area near a high concentration of oil refineries.

Figure 8: Location of Hydrogen Facilities in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation



B. Estimated 2008 Facility Emissions

In this section, a brief overview of the GHG, criteria pollutant, and TAC emissions from the facilities expected to be affected by the proposed regulation is provided.

Greenhouse Gas Emissions

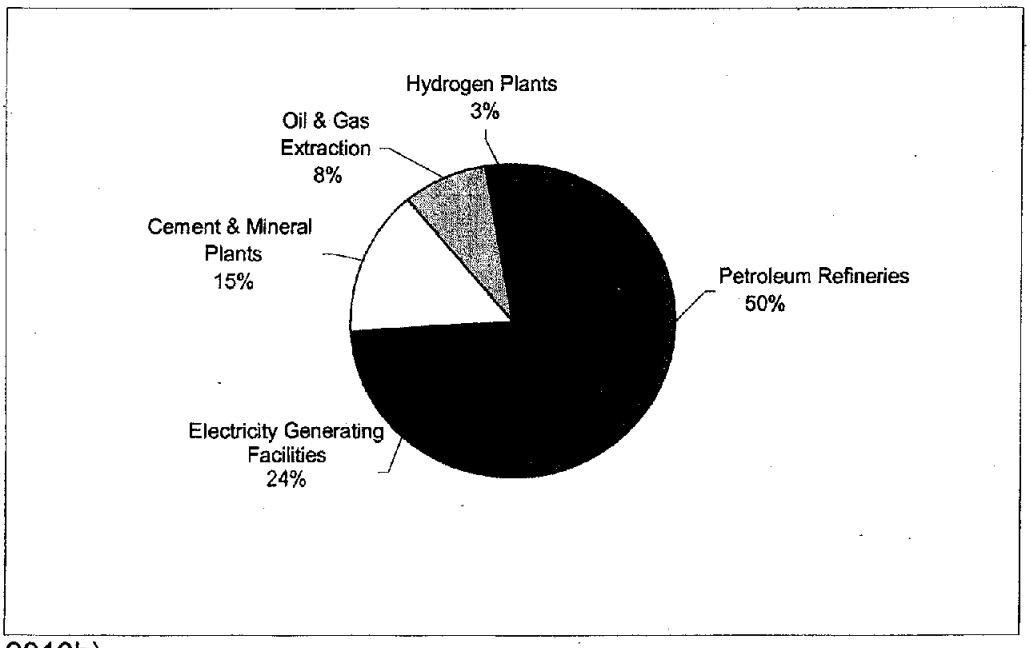
Statewide, the industrial sector as a whole emitted GHG emissions of about 160 $MMTCO_2e$ (ARB, 2010a). The approximately 60 facilities statewide expected to be subject to the proposed regulation were responsible for about 45 percent of those GHG emissions, or about 70 $MMTCO_2e$, and 60 percent of the GHG emissions from the facilities who were required to report for the Mandatory Reporting Regulation. (ARB, 2010b) Table 4 below provides the number of facilities in each industrial sector and the associated emissions. Figure 9 below provides a pie chart of the emissions distribution.

Table 4: 2008 GHG Emissions by Industrial Sector for the Facilities Expected to be Affected by the Proposed Energy Efficiency Assessment Regulation

Source Category	Number of facilities	Total 2008 Carbon Dioxide Equivalent Emissions (MMT)
Electricity Generating Facilities & Cogeneration Facilities	18	16
Petroleum Refineries	18	35
Oil & Gas Extraction	6	6
Cement Plants	10	9
Hydrogen Plants	3	2
Mineral Plant	1	2
Totals	56	70

(ARB, 2010b)

Figure 9: Distribution of 2008 GHG Emissions by Industrial Sector for the Facilities Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation



(ARB, 2010b)

As can be seen in Figure 9, refineries were responsible for about 50 percent of the GHG emissions from all of the facilities and sectors expected to be subject to the proposed requirements. The electricity generating facilities emissions listed in Table 2 and Figure 9 do not include the estimated 16 combined cycle plants that would be exempt from the proposal. The exempted facilities emitted about 25 $MMTCO_2e$ in 2008. (ARB, 2010b)

Criteria Pollutant Emissions

Table 5 shows a breakdown of the criteria pollutant emissions by industrial sector. These emissions estimates are from the California Emission Inventory Development and Reporting System (CEIDARS) for 2008.

Table 5: 2008 Criteria Pollutant Emissions by Industrial Sector for the Facilities Expected to be Subject to Proposed Energy Efficiency Assessment Regulation

Source Category	Number of Facilities	2008 EMISSIONS IN TONS PER YEAR				
		ROG	CO	SOx	NOx	Total PM
Electricity Generating Facilities (Power Plants) & Cogeneration Facilities	18	300	6,700	730	2,300	930
Petroleum Refineries	18	6,800	7,000	14,580	10,540	3,025
Oil & Gas Extraction	6	340	1,200	13	535	50
Cement Plants	10	310	13,500	1,970	20,570	5,600
Hydrogen Plants	3	60	25	2	53	14
Mineral Plants	1	30	300	230	1,840	600
Totals	56	7,840	31,725	17,525	35,840	10,220

Notes: Reactive organic gases (ROG); carbon monoxide (CO); oxides of sulfur (SOx); oxides of nitrogen (NOx); particulate matter (PM). Numbers may not add up to exact totals due to rounding.

Toxic Air Contaminant Emissions

TACs are also emitted from the industrial sectors identified in this report. Table 6 provides a representative listing of the more prevalent TACs by industrial sector. This list of TACs was established using the 2008 emissions data reported to the ARB from the approximately 60 impacted facilities distributed across the five source categories (i.e., cement and mineral plants, electricity generation, hydrogen plants, oil and gas extraction, and petroleum refineries). The emissions for each TAC was weighted based on their carcinogenic and non-carcinogenic health values and their potential for noninhalation impacts. All health information came from the Office of Environmental Health Hazard Assessment (OEHHA) Air Toxics Hot Spots Program Risk Assessment Guideline Manual for Preparation of Health Risk Assessments dated August 2003 and the Hot Spots Analysis and Reporting Program (HARP) Software. See Appendix B for more discussion on the scoring methodology.

The list of TACs for each industrial source category in Table 6 includes the carcinogenic TACs with the top scores or those that have an individually weighted cancer score greater than 50. In addition, the list also contains any substance with an individually weighted noncancer chronic or acute score greater than 50.

This scoring procedure is intended to rank the reported TACs based on emissions and associated health effects. This is a commonly used and simple method for prioritizing TACs. The results from this scoring procedure do not reflect the potential health impacts one might endure from actual exposures to facility emissions. Therefore, these scoring results should not be interpreted as a potential risk estimate or as risk assessment results. Rather, separate State law requires higher scoring facilities to perform health risk assessments (HRAs) containing additional information, and such facilities must undergo further analysis and modeling. Examples of additional

information that would be included in an HRA include the location and release characteristics of each TAC and several exposure assumptions.

Table 6: Toxic Air Contaminants by Industrial Source Category

Category	Pollutants Associated with the Development of Cancer	Pollutants Associated with Noncancer Health Effects
Cement Plants	1,3-Butadiene 3,3',4,4',5,5'-Hexachlorobiphenyl {PCB 169} Acetaldehyde Arsenic Benzene Beryllium Cadmium Chromium, hexavalent (& compounds) Diesel engine exhaust (Diesel PM) Dioxins {PCDDs} and Dibenzofurans (chlorinated) {PCDFs} [a] (total or individual) Epichlorohydrin Formaldehyde Naphthalene Nickel PAHs (total or individual) Vinyl Chloride	Acrolein Ammonia Hydrochloric acid Manganese Mercury Silica, crystalline (respirable)
Electricity Generation[b]	Arsenic Benzene Chromium, hexavalent (& compounds) Diesel engine exhaust (Diesel PM) Dioxins {PCDDs} and Dibenzofurans (chlorinated) {PCDFs} [a] (total or individual) Formaldehyde Naphthalene Nickel PAHs (total or individual)	Acrolein Manganese
Hydrogen Plants[c]	Benzene [c] PAHs (total or individual) [c]	
Mineral Plants	Arsenic compounds (inorganic) Cadmium Dioxins {PCDDs} and Dibenzofurans (chlorinated) {PCDFs} [a] (total or individual)	Hydrogen sulfide Sulfuric acid
Oil and Gas Production[c]	Diesel engine exhaust (Diesel PM) [c]	Ammonia [d]

Table 6: Toxic Air Contaminants by Industrial Source Category (continued)

Category	Pollutants Associated with the Development of Cancer	Pollutants Associated with Noncancer Health Effects
Refineries	1,3-Butadiene Arsenic Benzene Beryllium Cadmium Chromium, hexavalent (& compounds) Diesel engine exhaust (Diesel PM) Dioxins {PCDDs} and Dibenzofurans (chlorinated) {PCDFs} [a] (total or individual) Formaldehyde Naphthalene Nickel PAHs (total or individual)	Ammonia Manganese Mercury Sulfuric acid

a. Dioxins and Furans are assumed to be associated emissions. They are both included on this list if either group has a score greater than 50.
b. Includes power plants and cogeneration facilities.
c. Pollutant scores are less than 50.
d. Included based on emissions.

III. PROPOSED REGULATION

In this chapter, we discuss the key requirements of the proposed regulation for energy efficiency and co-benefit assessments of large industrial facilities. This chapter begins with a general summary of the regulation followed by a discussion of each major requirement of the proposed regulation. This chapter is intended to satisfy the requirements of Government Code section 11346.2, which requires that a noncontrolling "plain English" summary of the regulation be made available to the public.

A. Summary of the Proposed Regulation

The proposed regulation for Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities is included in Appendix A. The proposed regulation is designed to gather information on the energy efficiency improvement opportunities that are available for California's largest industrial stationary sources of GHG emissions and quantify the associated emission reductions for GHG, criteria pollutants, and TACs. The regulation includes requirements for the facility operator to conduct the one-time assessment and to submit this information to ARB.

The requirements of the proposed regulation applies to all facilities whose 2009 calendar year GHG emissions totaled 0.5 $MMTCO_2e$ or more, and cement plants and transportation fuel refineries that emitted GHG emissions of at least 0.25 $MMTCO_2e$ in 2009, as reported to ARB to comply with the Mandatory GHG Reporting Regulation. The regulation includes exemptions for combined-cycle electricity generating facilities (power plants) built after 1995, refineries that do not produce transportation fuels, and mobile and portable equipment.

Each facility subject to the proposed regulation must provide information on their processes and equipment types used, fuel and electricity consumption data, and emissions data for GHG, criteria pollutants, and TACs. The data provided must be from the 2009 calendar year, or the most recent applicable local district reporting year for criteria pollutants and TACs. The proposed regulation requires the facility operator to conduct a comprehensive analysis of potential energy efficiency improvements that could be made and assess the impacts associated with implementing the potential projects. The assessment must include the type of equipment, processes, or systems involved at the facility, the type of improvement projects identified and a description of each, the status of the projects if they are being considered by the facility for implementation, and estimations for timing, costs, project life, energy savings, and emission reductions of GHG, criteria pollutants, and TACs. The methodology used to estimate the emission reductions must be provided. For each potential project, the facility operator must identify impacts that would occur for complying with local district permitting or California Environmental Quality Act (CEQA) requirements, and any other impacts, such as those related to building, zoning, operations, safety, noise, water and other environmental impacts.

The proposal requires each facility operator to submit to ARB a report of all required information. This report is referred to as the Assessment Report. The Executive Officer would then review the Assessment Report for completeness and validity and work with the facility operator to obtain additional information, if necessary. If ARB determines an Assessment Report to be incomplete, a third-party assessment could be required. Completed Assessment Reports will be made publicly available online on ARB's Climate Change website.

A provision is included in the proposal to allow for a compliance extension if the facility operator can demonstrate that more time is necessary to complete and submit the assessment report. The compliance extension may be granted for up to 45 days if all requirements are met.

B. Discussion of the Proposed Regulation

Purpose

As stated in section 95150 of the proposed regulation, the purpose of the regulation is to require an energy efficiency assessment of California's largest industrial facilities to determine the potential for GHG emission reductions and other pollution reduction co-benefits. The assessment is meant to be a one-time evaluation of potential opportunities that will improve energy efficiency thereby reducing emissions.

Applicability

As stated in section 95151 of the proposed regulation, the regulation applies to operators of a facility in California with stationary sources that produce GHG emissions of at least 0.5 $MMTCO_2e$ in 2009. The regulation also applies to operators of a petroleum refinery in California that produces transportation fuels that are released into commerce if the facility produces at least 0.25 $MMTCO_2e$ of GHG emissions in 2009. Furthermore, operators of a cement plant in California that produces at least 0.25 $MMTCO_2e$ of GHG emissions in 2009 are also subject to the proposed regulation. The cumulative GHG emission totals for all facilities would be determined by the reports submitted by the facility operator to comply with the Mandatory GHG Reporting Regulation for the 2009 calendar year.

Exemptions

As stated in section 95152, the requirements of the proposed regulation do not apply to combined-cycle electricity generating facilities built after 1995. These facilities are known to have the most efficient power generation process and equipment available, as determined by the California Energy Commission. Staff believes that including them in the proposed regulation would not provide a benefit to the public or the State.
The proposed regulation also includes an exemption for petroleum refineries that do not produce transportation fuels, such as asphalt plants. This exemption is provided

because these processes are less energy intensive, emissions are typically less than transportation fuel refineries, and there are a limited number of facilities.

Lastly, the proposed regulation exempts mobile source combustion sources and portable equipment. The Scoping Plan measure for this regulation intended it to focus on stationary sources only, and mobile and portable equipment are not required reporting sources for the Mandatory GHG Reporting Regulation.

Definitions

The proposed regulation provides definitions of all terms that are not self-explanatory. There are about 70 definitions to help clarify and enforce the regulation requirements. Most of the definitions listed in proposed section 95153 are consistent with other adopted regulations, while others were developed by staff, with input from the public during workshops and workgroup meetings. Staff working on this regulation also coordinated with staff working on other GHG regulations to provide consistency where it was practical. Please refer to Appendix A, section 95153 for a list of definitions.

Energy Efficiency Assessment Requirements

As specified in section 95154, the proposed regulation requires the operator of facility types identified in section 95151 to conduct a Facility Energy Consumption and Emissions Analysis as well as an Energy Efficiency Improvement Analysis. The requirements are briefly discussed below.

1. Facility Energy Consumption and Emissions Analysis

The operator of each applicable facility must conduct a Facility Energy Consumption and Emissions Analysis. This analysis identifies the facility's processes and equipment types used in the processes and provides facility energy consumption and resulting GHG, criteria pollutant, and toxic air contaminant emissions. The data acquired in the analysis must be submitted to the ARB in the Assessment Report as is discussed later in the Reporting Requirements section of this chapter.

The required data includes, but is not limited to, facility type and contact information, a process flow diagram identifying each process or system and a description of each, as well as the equipment types used, the types of energy used for each process or system, and the facility energy use and emissions information for the 2009 calendar year. The fuel consumption and emissions must be consistent with what was reported for the Mandatory GHG Reporting Regulation and the district reporting for criteria pollutants and TACs. Facilities that were not required to report to the district in 2009 must include the latest calendar year reporting that was submitted. If not required to report to the local district, the proposed regulation requires that the local district reporting guidelines be followed to provide the emissions data.

The proposed regulation was not intended to create a new emissions inventory but instead to use data from existing reporting programs. However, having certified emissions data was an important consideration. The GHG data reported will be validated by a third party verification process that is required by the Mandatory GHG Reporting Regulation. The criteria pollutant and toxic air contaminant emission data will be validated by ARB and local district staff as part of their existing emission data management programs.

2. Energy Efficiency Improvement Analysis

The operator of each facility subject to the proposed regulation must conduct an Energy Efficiency Improvement Analysis. The Energy Efficiency Improvement Analysis must include the equipment, processes, and systems that cumulatively are responsible for at least 95 percent of the facility's GHG emissions that were reported in the Facility Energy Consumption and Emissions Analysis. This analysis covers the full range of potential energy efficiency improvement opportunities that exist at the facility, from those with relatively low costs that can be implemented quickly, to improvements requiring large expenditures that will take more time and have more extensive facility impacts. A facility that has participated in state- or federally-sponsored energy efficiency assessment programs would be allowed to use the information gathered from those assessments to fulfill portions of the assessment requirements. However, it is unlikely that those assessments will have all of the information that is required in the proposed regulation, so the facility operator would still be required to supplement the assessment program data with the information required in this section. The data acquired in this analysis must be submitted to the ARB in the Assessment Report.

The proposed regulation requires a facility-conducted versus a third party-conducted assessment. Staff has evaluated this option and determined that allowing a facility-conducted assessment is the best approach. Staff believes that it would result in a better product because the equipment and process experts would be conducting the assessment. Additionally, a self-assessment would reduce the amount of time required for rule development and implementation by at least one year by not having to establish a third-party assessor accreditation program. Finally, it would reduce the cost to the regulated community. However, the proposed regulation includes a third-party assessment back-stop, so that if ARB finds that the Assessment Report is incomplete, ARB could require the facility to conduct a third-party assessment. This element is discussed further in the Reporting Requirements section of this chapter.

The analysis data provided would include identification of the existing facility equipment, process, or system involved and the type of potential improvement, including a summary description. Potential improvements can include, but are not limited to, equipment upgrades or modifications, process changes, changes to operating procedures or maintenance practices, or investment in new technologies. The summary description should explain the system involved, the energy efficiency issues that have been identified, and a description of how the improvement would benefit energy efficiency.

The facility operator is required to provide a status of the improvement if it is being considered for, or has begun implementation or indicate that the facility is not implementing the project. Additionally, estimates on timing are required, including the estimated completion date for projects that are under investigation, scheduled, or on-going, and the actual completion date for those that have already been implemented. For projects that will not be implemented, the facility operator must provide a description of the rationale for not implementing the project.

The analysis must include preliminary cost estimates and project life. The facility operator must report the estimated one-time budgetary costs in 2010 dollars, including, but not limited to, capital costs of equipment, installation, design, construction, and permits. Estimated total average recurring annual budgetary costs are required in order to provide an understanding of the estimated ongoing costs associated with implementing the potential improvement project.

The estimated impacts on emissions must be assessed in this analysis. Estimated annual GHG, criteria pollutant, and TAC emission reductions and a specification of the methodology used to quantify them are required. The estimation method would include emission factors, control efficiency assumptions, and any other key assumptions used. This requirement is consistent with the local district reporting requirements for criteria pollutants and TACs.

Other impacts associated with implementing the potential energy efficiency improvement project must be included. Some of those impacts include identifying district permitting requirements, CEQA requirements, and other considerations, such as building, zoning, operational impacts, safety, noise, and other potential environmental impacts.

The data gathered in this analysis is meant to provide preliminary estimates on costs, emission reductions, and other impacts that would occur if the identified projects were implemented. Following the implementation of this proposed regulation, additional focus can occur on the impacts associated with implementing identified improvement projects that meet near-term and long-term emission reduction goals.

3. Alternative Approach Using Energy Consumption

The proposed regulation includes a provision that allows the facility operator to use energy consumption as the metric when determining which equipment, processes, or systems are evaluated in the energy efficiency improvement analysis. Under this provision, the facility operator would evaluate equipment, processes, or systems that cumulatively account for at least 95 percent of the facility's total energy consumption. The Executive Officer may approve this approach provided the analysis based on energy consumption also accounts for at least 95 percent of the facility's total GHG emissions.

4. Fuel Use Measurement Accuracy

The proposed regulation requires the operator to employ the same procedures for fuel use data measurements that are provided in the Mandatory GHG Reporting Regulation. This would achieve consistency when determining fuel usage for the Facility Energy Consumption and Emissions Analysis and Energy Efficiency Improvement Analysis.

Reporting Requirements

The operator of each covered facility must submit an Assessment Report to the ARB by December 15, 2011. The Facility Energy Consumption and Emissions Analysis and Energy Efficiency Improvement Analysis would be the key components of the Assessment Report. Reports are to be submitted via mail; an electronic method may also be used upon approval by the Executive Officer.

Document Retention, Recordkeeping, and Additional Data Requirements

The proposed regulation requires the facility operator to establish and document a system that provides clarity, transparency, and completeness of data and processes. This system must be sufficient to facilitate replication of the Assessment Report information. The proposed regulation also requires submittal of an Assessment Report that is in conformance with the data collection methodologies specified in their Assessment Report. This specifically refers to the methodologies used to quantify estimated emission reductions in the Facility Energy Consumption and Emissions Analysis and Energy Efficiency Improvement Analysis. The operator must retain documents regarding the procedures used to obtain the data supplied in the Assessment Report for a minimum of five years following submittal of the report to the ARB. The operator can retain additional data at the facility to be made available to ARB staff upon request.

Compliance Extension for Assessment Report

The proposed regulation includes an extension option for facility operators who are not able to meet the December 15, 2011, reporting deadline. The facility operatory would be required to apply for the extension by November 15, 2011, and specify the reasons for needing the additional time. Upon approval, the Executive Officer may grant an extension for up to 45 days.

Assessment Report Review, Validation, and Public Disclosure

The proposed regulation includes a process for determining Assessment Report completeness and disclosing the reports to the public. The Executive Officer is required to complete a review of the Assessment Report within 45 days of receipt, and determine whether it is complete as required in the previous sections and whether the data submitted are valid. The provision allows ARB to work with the facilities to gather additional information if there are deficiencies in the report, but if the Executive Officer

determines the report is incomplete, a third-party assessment may be required. This section states that completed Assessment Reports will be made available to the public on ARB's Climate Change website by April 30, 2012.

Third Party Assessment Report

In the event that a facility operator is required by the previous section to complete a third-party assessment, the operator is responsible for submitting a written application to the Executive Officer for approval of the operator's chosen third party assessor, including demonstration of the third party assessor's qualifications to effectively conduct a Facility Energy Consumption and Emissions Analysis and Energy Efficiency Improvement Analysis. The facility operator and the prospective third party assessor would each be required to sign a conflict of interest certification statement, and a quote from the third party assessor to conduct the required assessment is required. Once the Executive Officer approves the third party assessor, the operator must submit the completed third party Assessment Report within 90 days.

Confidentiality

The proposed regulation includes a confidentiality provision that explains how ARB will handle data submitted to comply with the requirements. Emissions data submitted to ARB is considered public information. Any other data submitted may be designated by the facility operator to be confidential because it may be a trade secret ormay be otherwise exempt from public disclosure under the California Public Records Act. ARB staff will handle those requests in accordance with State law. However, ARB staff believes it is critical that the information collected be publicly available, particularly to those communities that are located near the facilities. In developing the proposed regulation, ARB staff's goal was to require information that would provide sufficient detail about energy efficiency improvement projects to facilitate transparency, yet not reveal any confidential business information about the facility. As such, it is expected that a majority of the information received will not be confidential business data. In addition, ARB staff will work with the facility operators throughout the analysis and reporting process to address issues regarding confidentiality such that most if not all of the information provided to ARB can be directly released to the public.

Enforcement

As specified in section 95161, the proposed regulation explains the actions that would result in enforcement action, such as submittal of false information or failure to submit any report or include all information required.

Severability

The proposed regulation's severability clause is intended to ensure that if any portion of the regulation is deemed invalid, the remainder of the regulation will continue in full force and effect.

IV. ENVIRONMENTAL IMPACTS OF THE PROPOSED REGULATION

A. Air Quality and Environmental Impacts

The California Environmental Quality Act (CEQA) and ARB policy require an analysis to determine the potential adverse environmental impacts of proposed regulations. Because ARB's program for the adoption of regulations is certified by the Secretary of Resources (Public Resources Code, Section 21080.5, Exemption of specified regulatory programs), the CEQA analysis requirements are included in the ARB Staff Report (i.e., the Initial Statement of Reasons) in lieu of preparing an environmental impact report or negative declaration. In addition, ARB will respond in writing to all significant environmental points raised by the public during the public review period or at the Board hearing. These responses will be contained in the Final Statement of Reasons for the regulation.

Staff evaluated the potential environmental impacts from the proposed regulation and determined that no significant adverse environmental impacts are likely to result from the proposal. Further, staff has determined that adoption of the proposed regulation will not result in any significant adverse impacts on water quality, land, or biological resources.

This determination was made because the proposed regulation requires only reporting of GHG emissions, energy use, and energy assessments by specified facilities to ARB, and these activities produce no adverse environmental impacts. The collected data may be used in future programs to obtain further reductions in GHG, criteria pollutant and toxic air contaminant emissions. As such, any environmental benefits or impacts are too speculative for review at this time.

B. Public Process and Environmental Justice

State law defines environmental justice as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies (Senate Bill 115, Solis; Stats 1999, Ch. 690; Government Code § 65040.12(c)). The Board approved Environmental Justice Policies and Actions on December 13, 2001. These policies establish a framework for incorporating environmental justice into the ARB's programs consistent with the directives of State law. The policies subsequently developed apply to all communities in California, but they recognize that environmental justice issues have been raised more in the context of low income and minority communities, which sometimes experience higher exposures to some pollutants as a result of their proximity to multiple sources of air pollutants.

Actions of the ARB, local air districts, and federal air pollution control programs have made substantial progress towards improving the air quality in California. However,

some communities continue to experience higher exposures than others because of the cumulative impacts of air pollution from multiple sources.

Adoption and implementation of this regulation will have no negative environmental impacts on environmental justice communities. Facilities throughout the State will be required to report their GHG emissions, with the focus on those facilities producing the highest levels of emissions. The regulation will require a one time reporting for all facilities emitting over specified emission levels in California, including all cement plants and refineries producing transportation fuels. Staff will make this information available to the public.

To ensure that everyone has had an opportunity to stay informed and participate fully in the development of the regulation, staff has held multiple workshops and workgroup meetings, provided opportunities to participate in meetings by internet webcasting and telephone, widely distributed all materials, and maintained consistent contact with interested community and environmental representatives.

V. ECONOMIC IMPACTS OF THE PROPOSED REGULATION

In this chapter, we provide the estimated costs to businesses to comply with the proposed regulation. As stated previously, the proposed regulation will affect about 60 facilities in the State. ARB staff has quantified the economic impacts to the extent feasible, using preliminary cost estimates provided by facility operators and consultants that conduct energy efficiency assessments for large industrial facilities and staff's general knowledge of emissions reporting. Due to the many site-specific factors that are attributed to each industrial sector and individual facilities, a comprehensive cost analysis of each affected facility was not feasible. The cost estimates provided are based on the average or typical costs for the actions necessary to comply with the proposed regulation and serve to provide a general picture of the economic impacts that typical businesses subject to the proposed regulation might encounter. It is acknowledged that the actual costs to individual affected businesses may be lower or higher than that estimated.

Below we provide a summary of the costs, the legal requirements for the fiscal analysis, a discussion on our methodology used to estimate the costs, and the estimated costs and impacts on California businesses as well as on State and local governments.

A. Summary of Costs and Economic Impacts

ARB staff estimates that the total cost of the proposed regulation to affected businesses would be approximately $14 million over a period of about 16 to 18 months. A summary of the expected costs by grouped industrial sectors is provided below in Table 7. As can be seen, the majority of the costs will be borne by refineries and oil and gas extraction facilities which account for about $10 million or 75 percent of the total costs.

Table 7: Estimated Facility Costs and Total Costs for Compliance with the Proposed Regulation

Industrial Sectors	Number of Facilities	Estimated Cost per Facility ($2009)	Total Costs ($2009)
Electricity Generating Facilities and Hydrogen Plants	21	$78,000	$1,638,000
Cement and Mineral Plants	11	$175,000	$1,925,000
Petroleum Refineries and Oil & Gas Extraction and Transmission	24	$425,000	$10,200,000
Totals	56	N/A	$13,763,000

Overall, the vast majority of the affected businesses are large businesses, many owned by multi-national corporations, and therefore, we do not expect their profitability to be adversely impacted. As a result, we do not expect a noticeable change in employment,

business creation, expansion, or elimination, or business competitiveness in California. We also found no adverse economic impacts to any local or federal agencies. ARB will incur minimum costs to administer the proposed regulation. These costs would be met with existing resources. No other State agencies will be affected.

No job or business losses are anticipated in California due to the regulation. However, there may be a small increase in the amount of work for consultants in the event facility operators out-source the work needed to fulfill the requirements in the proposed regulation.

All the cost estimates provided in this chapter are relative to the year 2009 (current value of the costs), and all costs are given in 2009 dollars. The information, assumptions and methodologies used to determine compliance costs are summarized in this chapter.

B. Legal Requirements

Section 11346.3 of the Government Code requires that, in proposing to adopt or amend any administrative regulation, State agencies must assess the potential for adverse economic impacts on California business enterprises and individuals, including the ability of California businesses to compete with businesses in other states. The assessment must also include the potential impact of the regulation on California jobs; business expansion, elimination or creation; and the ability of California business to compete with businesses in other states.

Also, State agencies are required to estimate the cost or savings to any State or local agency and school district in accordance with instructions adopted by the Department of Finance. The estimate shall include any non-discretionary cost or savings to local agencies, and the cost or savings in federal funding to the State.

HSC section 57005 requires ARB to perform an economic impact analysis of submitted alternatives to the proposed regulation before adopting any major regulation. A major regulation is defined as a regulation that will have a potential cost to California business enterprises in an amount exceeding $10 million in any single year. Because the total cost of the regulation is estimated at approximately $14 million, the proposed regulation is being considered a major regulation.

C. Analysis of Estimated Costs for Compliance

The following is a description of the methodology used to estimate costs, as well as the estimated costs to facilities that will be affected by the proposed regulation.

Compliance with the proposed regulation will require facility operators to undertake a variety of actions, some that may be done routinely for other programs or to optimize facility operations and others that will be taken solely for compliance with the proposed

regulation. These include actions such as collecting and analyzing facility energy use data and associated GHG, criteria pollutant and toxic air contaminant emissions; developing process flow diagrams for the facility; identifying energy efficiency improvement projects or opportunities and the associated costs; estimating energy savings and emissions impacts; and any other implementation activities.

For the cost analysis, ARB staff relied on preliminary cost estimates provided by facility operators and consultants that conduct energy efficiency assessments for large industrial facilities and staff's general knowledge of emissions reporting. ARB staff used these cost estimates to develop cost ranges and the average costs for facilities based on the expected complexity (low, medium, or high) of the reporting facilities. Refineries and oil and gas extraction facilities were characterized as high complexity facilities, cement and mineral facilities as medium complexity, and electricity generating and hydrogen plants as low complexity. The average costs for each grouping of facilities was used to estimate the costs for an individual facility and then multiplied by the total number of facilities to determine the total costs for the industrial sectors within each "complexity" grouping.

Table 8 provides a summary of the estimated cost ranges and average costs for compliance with the proposed regulation based on the expected complexity of the facilities within the five industrial sectors.

Table 8: Estimated Cost Ranges and Average Cost for Compliance with the Proposed Regulation

Complexity	Industrial Sector	Number of Facilities	Estimated Cost per Facility ($2009)		
			Low	High	Average
Low	Electricity Generating Facilities and Hydrogen Plants	21	$6,000	$150,000	$78,000
Medium	Cement and Mineral Plants	11	$100,000	$250,000	$175,000
High	Petroleum Refineries and Oil & Gas Extraction and Transmission	24	$250,000	$600,000	$425,000

As can be seen, the "high complexity" facilities, such as refinery or oil and gas extraction facilities have higher compliance costs, ranging from $250,000 to $600,000 per facility, than the "medium complexity" facilities such as cement or mineral plants, which range from $100,000 to $250,000 and the "low complexity" facilities, which range from $6,000 to $150,000 per facility. This is not unexpected, as a refinery or oil and gas extraction facility typically will have numerous processes, process functions, and energy sources involved in the collection or processing of oil. Electricity generating facilities are much simpler in design, typically having one or more natural gas turbine generators and auxiliary equipment.

There is variability within the range of estimated costs within the facility groupings. Each facility is unique. Individual costs, even for the same types of facilities, could vary substantially. This variability is due to the size and complexity of the facility, the presence of existing staffing and systems to assist with estimating emissions, developing an energy efficiency improvement analysis, and other factors. A precise estimate of overall reporting costs for an individual facility is difficult to develop.

In our analysis, we used the average costs to represent the typical costs to a business and estimate the total costs for compliance with the proposed regulation. While the actual costs to individual affected businesses may be lower or higher than that estimated, ARB staff believe the cost estimates developed based on the average costs listed in Table 8 provide a good approximation of the overall costs to businesses in California to comply with the proposed regulation.

Table 9 provides a summary of the expected average costs for each facility within a given industrial sector and the total costs for compliance with the proposed regulation.[5] As is shown, the costs for all businesses to comply with the proposed regulation are estimated to be approximately $14 million. About 75 percent of the costs are borne by the petroleum refineries and oil and gas extraction facilities. The "medium complexity" facilities, cement and mineral plants, account for about $2 million or about 15 percent of the total costs. Cost estimates for the electricity generating facilities and hydrogen plants are about $1.6 million or 10 percent of the total costs.

Table 9: Estimated Facility Costs and Total Costs for Compliance with the Proposed Regulation

Complexity	Industrial Sectors	Number of Facilities	Estimated Cost per Facility ($2009)	Total Costs ($2009)
Low	Electricity Generating Facilities and Hydrogen Plants	21	$78,000	$1,638,000
Medium	Cement and Mineral Plants	11	$175,000	$1,925,000
High	Petroleum Refineries and Oil & Gas Extraction and Transmission	24	$425,000	$10,200,000
	Totals	56	N/A	$13,763,000

[5] As discussed previously in this staff report, there are about 60 facilities that will be affected by the proposed regulation. Of these, four are electricity generating facilities operated by local agencies in Southern California. Because these facilities operate as not-for-profit corporations and can recover costs from the clients they serve, their costs for compliance are included in the total costs of the proposed regulation.

D. Economic Impacts of Proposed Regulation

In this section, we analyze the potential impacts of the estimated costs of the proposed regulation on business enterprises in California. Section 11346.3 of the Government Code requires that, in proposing to adopt or amend any administration regulation, State agencies shall assess the potential for adverse economic impact on California business enterprises and individuals. The assessment shall include a consideration of the impact of the proposed or amended regulation on the ability of California businesses to compete with businesses in other states, the impact on California jobs, and the impact on California business expansion, elimination, or creation.

1. Potential Business Impacts

The proposed regulation focuses on the largest stationary sources of GHG emissions and includes refineries, oil and gas extraction facilities, cement plants, a mineral plant, hydrogen plants, and electricity generating facilities. With the exception of about four electricity generating facilities that are operated by local municipal and county governments, the vast majority of the business that will be affected by the proposed regulation are large businesses, many owned by multi-national corporations. A list of the affected businesses is provided below in Table 10. None of the businesses are considered to be small businesses.

Table 10: Facilities in California Expected to be Subject to the Proposed Energy Efficiency Assessment Regulation

Facility Name	Industrial Sector
CalPortland Company, Colton Plant	Cement Plant
CalPortland Company, Mojave Plant	Cement Plant
Cemex - Black Mountain Quarry	Cement Plant
Cemex - Cement Plant Davenport	Cement Plant
Lehigh Southwest Cement Co - Redding	Cement Plant
Lehigh Southwest Cement Co. - Tehachapi	Cement Plant
Lehigh Southwest Cement Company - Cupertino	Cement Plant
Mitsubishi Cement 2000	Cement Plant
National Cement Company - Lebec	Cement Plant
TXI Riverside Cement (Oro Grande Plant)	Cement Plant
Burney Forest Products	Cogeneration Facility
Kern River Cogeneration Company	Cogeneration Facility
Midway-Sunset Cogeneration	Cogeneration Facility
Stockton CoGen	Cogeneration Facility
Sycamore Cogeneration Co	Cogeneration Facility
ACE Cogeneration	Electricity Generation
AES Alamitos, LLC	Electricity Generation
Aes Huntington Beach, Llc	Electricity Generation
Colmac Energy, Inc. 92254	Electricity Generation
Covanta Delano, Inc.	Electricity Generation
Dynegy South Bay, LLC	Electricity Generation
Los Angeles Department of Water & Power-Haynes Generating Station	Electricity Generation
Los Angeles Department of Water & Power-Scattergood Generating Station	Electricity Generation
Los Angeles Department of Water & Power-Valley Generating Station	Electricity Generation
NRG Energy - Encina	Electricity Generation
Puente Hills Landfill, LA County Sanitation	Electricity Generation
RRI Energy Etiwanda, Inc.	Electricity Generation
Wheelabrator Shasta Energy Company	Electricity Generation
Aera Energy LLC, Belridge, 93251	Oil & Gas Extraction
Aera Energy LLC, MOCO, D&E, 93252	Oil & Gas Extraction
Chevron U.S.A Inc - Cymric Asset, 93251	Oil & Gas Extraction
Chevron U.S.A Inc - Midway Sunset Asset, 93225	Oil & Gas Extraction
Occidental Of Elk Hills, Inc.	Oil & Gas Extraction
Plains Exploration & Production Company - San Joaquin Heavy Oil Production Facility	Oil & Gas Extraction
Searles Valley Minerals	Mineral Plant
Air Liquide El Segundo Hydrogen Plant	Hydrogen Plant
Air Products Carson Hydrogen Plant	Hydrogen Plant

Facility Name (continued...)	Industrial Sector
Big West of California Bakersfield Refinery (Area 3)	Petroleum Refinery
Big West of California Bakersfield Refinery (Areas 1&2)	Petroleum Refinery
BP West Coast Products LLC, Refinery	Petroleum Refinery
Chevron Products Company - El Segundo Refinery, 90245	Petroleum Refinery
Chevron Products Company - Richmond Refinery, 94802	Petroleum Refinery
Conoco Phillips Refining Company	Petroleum Refinery
ConocoPhillips Los Angeles Refinery Wilmington Plant	Petroleum Refinery
ConocoPhillips Los Angeles Refinery, Carson Plant	Petroleum Refinery
ConocoPhillips Santa Maria Refinery	Petroleum Refinery
ExxonMobil Torrance Refinery	Petroleum Refinery
Kern Oil and Refining Company	Petroleum Refinery
Paramount Petroleum Corporation	Petroleum Refinery
San Joaquin Refining Company	Petroleum Refinery
Shell Oil Products US	Petroleum Refinery
Tesoro Refining And Marketing Co. - LAR	Petroleum Refinery
Tesoro Refining and Marketing Company, 94553	Petroleum Refinery
Ultramar Inc - Valero	Petroleum Refinery
Valero Refining Company -California, Benicia Refinery and Benicia Asphalt Plant	Petroleum Refinery

Analysis of Return on Owner's Equity (ROE)

To determine the potential business impacts, ARB staff conducted an analysis comparing the annual return on owner's equity (ROE) for affected businesses before and after the inclusion of the costs associated with the proposed regulation. The analysis uses publicly available information to assess the impacts on competitiveness, jobs, and business expansion, elimination, or creation. As stated previously, ARB staff estimates approximately 60 businesses will be affected by the proposed regulation.

The approach used in evaluating the potential economic impact of the proposed regulation on California businesses is as follows:

(1) Affected businesses were identified using the applicability criteria for the proposed regulation and the 2008 calendar year GHG emissions data reported pursuant to the Mandatory GHG Reporting Regulation. See Table 10 above for a listing of affected businesses.

(2) The costs for the regulation were estimated for each of these businesses based on the estimated costs to conduct the assessment for each type of industrial sector and the number of facilities it owns (see Table 9).

(3) The total annual cost for each business is adjusted for both federal and state taxes.

(4) Three year average (2007-2009) financial data are used to calculate the ROE for each affected business where such data were available. The adjusted cost is subtracted from net profit data to calculate the ROE after the regulation. The ROE before and after the regulation are compared to determine the impact on the profitability of the businesses. A reduction of more than 10 percent in profitability is considered to indicate a potential for significant adverse economic impacts. This threshold is consistent with the thresholds used by the U.S. EPA and others.

Table 11 presents the average ROE of the businesses in the affected industries.

Table 11: Affected Businesses with Change in ROE

Complexity	Industrial Sector	Number of Facilities	Estimated Percent Change in ROE
Low	Electricity Generating Facilities and Hydrogen Plants	21	-0.25
Medium	Cement and Mineral Plants	11	-0.07
High	Petroleum Refineries and Oil & Gas Extraction and Transmission	24	-0.06
Overall Average			-0.1

California businesses are affected by the cost of the proposed regulation to the extent that the implementation of the proposed regulation reduces their profitability. As shown in Table 11, the proposed regulation would reduce the average profitability of the affected businesses by about 0.1 percent. Electricity generating facilities and hydrogen plants would be affected the most and petroleum refineries and oil and gas extraction and transmission facilities would be affected the least. Overall, our analysis shows that the affected businesses will be able to absorb the costs of the proposed regulation with no significant adverse impacts on their profitability. Because the proposed regulation would not alter significantly the profitability of these businesses, we do not expect a noticeable change in employment, business creation, elimination, or expansion, and business competitiveness in California.

2. Impacts to Small Businesses

We are not aware of any small business[6] that would be affected by the proposed regulation. As noted previously, the proposed regulation would apply to only the largest industrial stationary sources of emissions in California. These sources are generally not operated by small businesses.

3. Potential Impact on Business Competitiveness

The affected businesses are large businesses and can either absorb or pass-through the increased costs associated with the proposed regulation with no significant impact on their ability to compete with non-California businesses. For these reasons, we do not believe the relatively low costs of this proposed regulation are high enough to significantly affect the competitiveness of the businesses that are affected by the proposed regulation.

4. Potential Impact on Employment, Business Creation, Elimination, or Expansion

No change is expected to occur in the status of California businesses as a result of the proposed regulation. This is because the proposed regulation is expected to impose a minor cost on businesses in California.

Staff believes that the proposed regulation may slightly increase additional work for existing businesses in California in the event facilities choose to out-source the work needed to comply with the requirements in the proposed regulation. This work would likely be in the fields of technical consulting to assist affected businesses in preparing their GHG, criteria pollutant, and air toxic contaminant emissions reports and energy efficiency improvement analyses. Because some of the reporting and analysis will be done by the facilities and some work will be done by consultants from existing firms for both individual facilities or groups of facilities, precise estimates of the number of jobs created are not possible. However, given that the assessments are a one-time requirement, we anticipate that the work will be done with existing resources in most cases.

---

[6] Small business definition: Independently owned and operated; and, cannot be dominant in its field of operation; and, must have its principal office located in California; and must have its owners (or officers in the case of a corporation) domiciled in California; and, together with its affiliates, be either: a business with 100 or fewer employees, and an average annual gross receipts of $12 million or less over the previous three tax years, or a manufacturer with 100 or fewer employees. http://www.pd.dgs.ca.gov/smbus/sbcert.htm (DGS 2007)

5. Impacts to Federal, State, and Local Agencies

There are no State agencies that have any facilities that are subject to this regulation. As discussed below, there are four facilities operated by local agencies that will be affected. We are not aware of any facilities affected by the proposed regulation that are operated by the federal government.

With regards to local governments, the Los Angeles Department of Water and Power (LADWP) owns three electricity generating facilities that are subject to the proposed regulation. In addition, the Puente Hill Landfill electricity generating facility is operated by the Los Angeles County Sanitation District (LASCD). These facilities operate as not-for-profit corporations; thus their compliance costs, about $78,000 per facility or about $300,000 combined, are included in the total costs of the proposed regulation as presented earlier in this chapter. Both LADWP and LASCD are expected to cover the estimated compliance costs from within their existing budgets. The proposed regulation will not significantly impact City or County of Los Angeles tax payers through fiscal budgets.

ARB will incur minimum costs to administer the proposed regulation. These costs would be met with existing resources. No other State agencies will be affected.

6. Necessity of Reporting

This regulation is proposed under AB 32 and other authority to receive vital information for use toward achieving the critical public health and welfare goals of reducing GHG and other air pollutant emissions. This additional information is needed to identify promising areas for emission reductions that may not otherwise be identified. The reporting requirements needed to obtain this information will apply to businesses, namely, the largest GHG-emitters in the State. As such, ARB finds that the reporting requirements of the proposed regulation are necessary for the health and welfare of the people of California.

E. Alternatives to the Proposed Regulation

Government Code section 11346.2 requires ARB to consider and evaluate reasonable alternatives to the proposed regulation and provide the reasons for rejecting those alternatives. ARB staff evaluated four alternative strategies to the current proposal. Based on the analysis, none of the alternative control strategies were considered to be more effective than the proposed regulation. Full implementation of the proposed regulation is necessary to achieve ARB's goal, as described in the AB 32 Scoping Plan, to require an energy efficiency assessment of the stationary sources within the largest industrial facilities to determine the opportunities for GHG emission reductions and co-benefits for other pollutants. A description of the alternatives considered and staff's rationale for finding them unsuitable follows below.

Alternative 1: Do Not Adopt This Regulation: Rely on Facilities to Voluntarily Conduct an Energy Efficiency Assessment

One alternative would be to do nothing and rely on existing voluntary programs. As mentioned in previous chapters, several programs are currently available to provide industrial facilities with information, tools, and opportunities for improving energy efficiency. However, none of the existing programs are comprehensive enough to result in a full assessment of the energy efficiency and emission reductions opportunities that exist at industrial facilities. The voluntary programs are focused on specific processes and short payback periods as opposed to providing a full range of opportunities for both the near-term and long-term. The proposed regulation does, however, allow the data acquired from participation in programs such as these to be used in order to meet applicable portions of the requirements where appropriate. Staff believes the proposed regulation will provide a list of feasible energy efficiency and emission reduction opportunities that is far more comprehensive than the existing voluntary programs. Therefore, ARB staff does not recommend this alternative.

Alternative 2: Require a Third-Party Assessment

Another option would be to require the facility assessments to be performed by a third party. Staff believes that requiring third party assessments would increase the costs to the regulated community and ARB and increase the amount of time needed for rulemaking and implementation, since ARB would need to develop a third-party assessor accreditation program. Staff estimates that a third-party assessment would cost about twice as much as a facility-conducted assessment, about $28 million, and would result in an inferior product, because it is estimated that few, if any, sources outside of the facility have the expertise comparable to the facility process and equipment experts. However, the proposed regulation includes a third-party assessment back-stop, so that if ARB determines an Assessment Report to be incomplete, the operator must conduct a third-party assessment. Therefore, ARB staff does not recommend this alternative.

Alternative 3: Adopt Requirements for Refineries Only

Another option would be to adopt requirements only for refineries, which comprise about 50 percent of the GHG emissions from the facilities being affected by the proposed regulation, and not address the energy efficiency and emission reduction opportunities at other industrial facilities. This option would result in costs of about $7.6 million, reducing the overall cost by about 50 percent. However, it would not provide the information necessary to determine the opportunities that exist at other facilities that have significant GHG emissions, and would therefore, not fulfill the goals of the AB 32 Scoping Plan measure. The current proposal would provide ARB with the necessary data to inform our emission reduction programs for the largest industrial facilities in the State in order to design approaches to maximize GHG, criteria pollutant, and toxic air contaminant reductions. Therefore, ARB staff does not recommend this alternative.

Alternative 4: Require ARB Staff to Conduct the Assessment

The last alternative option considered is to require ARB staff to conduct the assessments for each facility. While this option would reduce the costs to the affected facilities, it would increase costs to the ARB. ARB staff has the experience and knowledge necessary to review the assessment conducted by the facilities, but conducting the assessments would require in-depth training and certification through existing programs such as DOE's Industrial Technologies Program to ensure staff are qualified energy experts. Costs associated with certification and travel would be significant. Additionally, implementation of the proposed regulation would require more time, with the final reports not likely to be completed before the end of 2012. This would be in part due to the time it would take to certify and train sufficient ARB staff to conduct the assessments and due to the fact that there is a limited number of ARB staff that could be made available to do the assessments. Therefore, ARB staff does not recommend this alternative.

REFERENCES

(Air Products, 2009) Presentation and tour of Air Products facility in Wilmington, CA. May 4, 2009.

(ARB, 2008) *Climate Change Scoping Plan*, pp. 54-55, California Air Resources Board, December 2008.

(ARB, 2009) *Preliminary Draft Regulation for a California Cap-And-Trade Program: a California Cap on Greenhouse Gas Emissions and Market Based Compliance Mechanism.* California Air Resources Board. November 24, 2009.

(ARB, 2010a) California Air Resources Board Greenhouse Gas Inventory Data http://www.arb.ca.gov/cc/inventory/data/data.htm. Accessed May 28, 2010.

(ARB, 2010b) *Mandatory Greenhouse Gas Reporting 2008 Reported Emissions, California Air Resources Board.* http://www.arb.ca.gov/cc/reporting/ghg-rep/facility_summary.xls, Report generated February 4, 2010.

(ARB GHG, 2009) *Mandatory Reporting of Greenhouse Gas Emissions: Instructional Guidance for Operators*, CHAPTER 7: CEMENT PLANTS. ARB, July 2009. http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep-guid/ghg-rep-guid.htm

(ATP, 2010) *Important Facts About ATP*, Advanced Technology Program,http://www.atp.nist.gov/atp/imp_fact.htm. Accessed April 28, 2010.

(CAPCOA, 1990) *Air Toxics "Hot Spots" Program.* Facility Prioritization Guidelines. July 1990. http://www.arb.ca.gov/ab2588/RRAP-IWRA/priguide.pdf

(CEC, 2009) *Energy Efficiency in Industrial Plants*, presentation by the California Energy Commission, Energy Academy. February, 17, 2009.

(DOE, 2010) U.S. Department of Energy, Energy Efficiency and Renewable Energy, Industrial Technologies Program website, http://www1.eere.energy.gov/industry/saveenergynow/assessments.html and http://www1.eere.energy.gov/industry/saveenergynow/energy_experts.html. Accessed April 28, 2010.

(EIA, 2010) *State Energy Profile – California*, U.S. Energy Information Administration, Independent Statistics and Analysis, updated April 29, 2010, http://tonto.eia.doe.gov/state/state_energy_profiles.cfm?sid=CA. Accessed April 30, 2010.

(U.S. EPA, 2010) U.S. Environmental Protection Agency's website for Energy Star Program for Buildings and Plants. http://www.energystar.gov/index.cfm?c=business.bus_index. Accessed May 24, 2010

(LBNL, 2005) Ernst Worrell and Christina Galitsky. *Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries: An ENERGY STAR® Guide for Energy and Plant Managers.* Energy Analysis Department. Environmental Energy Technologies Division. Ernest Orlando Lawrence Berkeley National Laboratory. pp. 1-11. February 2005.

(NPPC, 2002) "*Natural gas combined-cycle gas turbine power plants*" Northwest Power Planning Council New Resource Characterization for the Fifth Power Plan, August 8, 2002

(OEHHA, 2003) *Air Toxics Hot Spots Program Risk Assessment Guidelines.* The Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments. August 2003. http://www.oehha.ca.gov/air/hot_spots/pdf/HRAguidefinal.pdf

(PG&E, 2010) *Pacific Gas & Electric Large Business Energy Management website for Industrial Sources.* http://www.pge.com/mybusiness/energysavingsrebates/incentivesbyindustry/industrial/. Accessed May 18, 2010.

(SVM, 2009) Searles Valley Minerals website: http://www.svminerals.com/. Accessed September 9, 2009.

(TCPA, 2008) The Energy Repot, Chapter 22 Hydrogen, Texas Comptroller of Public Accounts, Research and Analysis Division, Austin Texas. May 6, 2008. http://www.window.state.tx.us/specialrpt/energy/renewable/h2.php. Accessed May 19, 2010

(Tribal Energy, 2010) oil and Gas Resources and Their Uses, http://teeic.anl.gov/er/oilgas/restech/uses/index.cfm. Accessed May 11, 2010

(Worrell and Galitsky, 2004). Ernst Orlando Lawrence Berkeley National Laboratory. *Profile of the Petroleum Refining Industry in California.* Ernst Worrell and Christina Galitsky. March 2004.

(Worrell and Galitsky, 2005). Ernst Orlando Lawrence Berkeley National Laboratory. *Energy Efficiency Improvement and Cost Saving Opportunities For Petroleum Refineries.* Ernst Worrell and Christina Galitsky. February 2005.

Appendix A

Proposed Regulation for Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities

-This page is intentionally blank-

PROPOSED REGULATION FOR ENERGY EFFICIENCY AND CO-BENEFITS ASSESSMENT OF LARGE INDUSTRIAL FACILITIES

Adopt new Article 2.1 in Subchapter 10, sections 95150 to 95162, title 17, California Code of Regulations, to read as follows:

Article 2.1: Energy Efficiency and Co-Benefits Assessment of Large Industrial Facilities

§ 95150. Purpose

The purpose of this article is to require an energy efficiency assessment of California's large industrial facilities to determine the potential for greenhouse gas emission reductions and other pollution reduction co-benefits.

NOTE: Authority Cited: Sections 38510, 38530, 38560, 38562, 39600, 39601, 39659, and 41511, Health and Safety Code. Reference: Sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, 39003, 39500, 39600, 39601, 39659, and 4151, Health and Safety Code.

§ 95151. Applicability

(a) Except as provided in subsection 95152, this article applies to the following entities:

(1) Operators of a facility with stationary sources in California that produce greenhouse gas emissions of 0.5 million metric tonnes of carbon dioxide (CO_2) equivalent ($MMTCO_2e$) or more annually. This total is to be determined by the reporting submitted by the facility operator to comply with the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, sections 95100 to 95133, title 17, California Code of Regulations, for the calendar year 2009;

(2) Operators of any petroleum refinery in California that produces petroleum-based transportation fuels that are released into commerce and that produces greenhouse gas emissions of 0.25 $MMTCO_2e$ or more annually as determined by the reporting submitted by the facility operator to comply with the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, sections 95100 to 95133, title 17, California Code of Regulations, for the calendar year 2009; and

(3) Operators of any cement plant in California that produces greenhouse gas emissions of 0.25 $MMTCO_2e$ or more annually as determined by the reporting submitted by the facility operator to comply with the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, sections 95100 to 95133, title 17, California Code of Regulations, for the calendar year 2009.

(b) The Executive Officer may request a demonstration from any entity operating a facility to establish that a specified facility does not meet the applicability criteria specified in section 95151(a). Such demonstration must be provided to the Executive Officer within 30 days of a written request received from the Executive Officer.

NOTE: Authority Cited: Sections 38510, 38530, 38560, 38562, 39600, 39601, 39659, and 41511, Health and Safety Code. Reference: Sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, 39003, 39500, 39600, 39601, 39659, and 4151, Health and Safety Code.

§ 95152. Exemptions.

The requirements of this article do not apply to the following:

(a) Combined cycle electricity generating facilities built after 1995;

(b) Petroleum refineries that do not produce transportation fuels; and

(c) Mobile combustion sources as defined in section 95153(a)(40) or portable equipment as defined in section 95153(a)(53).

NOTE: Authority Cited: Sections 38510, 38530, 38560, 38562, 39600, 39601, 39659, and 41511, Health and Safety Code. Reference: Sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, 39003, 39500, 39600, 39601, 39659, and 4151, Health and Safety Code.

§ 95153. Definitions.

(a) For the purposes of this article, the following definitions apply:

(1) "ARB" means the California Air Resources Board.

(2) "Assessment Report" or "report" means the report of the facility energy consumption and emissions analysis and energy efficiency improvement analysis prepared by an operator or third party entity and submitted to ARB pursuant to sections 95154 and 95155.

(3) "Average recurring annual budgetary cost" means the expected annual budgetary cost associated with implementing an energy efficiency improvement project, averaged over the project life. The annual cost must include, but is not limited to, operation and maintenance of the energy efficiency improvement project.

(4) "British Thermal Unit" or "Btu" means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.

(5) "Budgetary cost estimate" means a cost estimate that is used for project comparison purposes, but does not require detailed engineering and therefore has a correspondingly lower accuracy.

(6) "Calendar year" means the time period from January 1 through December 31.

(7) "California Environmental Quality Act" or "CEQA" means California Public Resources Code Sections 21000 et seq.

(8) "Carbon dioxide" or "CO_2" means the most common of the six primary greenhouse gases, consisting on a molecular level of a single carbon atom and two oxygen atoms.

(9) "Carbon dioxide equivalent" or "CO_2 equivalent" or "CO_2e" means a measure for comparing carbon dioxide with other GHGs, based on the quantity of those gases multiplied by the appropriate global warming potential (GWP) factor and commonly expressed as metric tonnes of carbon dioxide equivalents ($MTCO_2e$).

(10) "Cement plant" means an industrial structure, installation, plant, or building primarily engaged in manufacturing Portland, natural, masonry, pozzolanic, and other hydraulic cements, and typically identified by NAICS code 327310.

(11) "Clinker" means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.

(12) "Combined cycle electricity generating facility" means an electricity generating facility that uses the waste heat from a gas turbine to provide heat energy for a steam turbine.

(13) "Criteria air pollutant" means substances identified in title 17, California Code of Regulations, Section 70200. Examples include ozone, carbon monoxide, nitrogen dioxide, sulfur dioxide, particulate matter with aerodynamic diameters of 10 microns or less (PM10) and PM 2.5.

(14) "Distillate fuel oil" means a general classification for a petroleum fraction produced in conventional distillation operations. It includes diesel fuels and fuel oils.

(15) "District" has the same meaning as defined in the California Health and Safety Code, Section 39025.

(16) "Electricity generating facility" means a facility that generates electricity and includes one or more generating units at the same location.

(17) "Emissions" means the release of greenhouse gases, criteria air pollutants, or toxic air contaminants into the atmosphere from sources and processes in a facility.

(18) "Emissions data report" or "greenhouse gas emissions data report" means the report prepared by an operator each year and submitted by electronic means to ARB that provides the information required by the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, sections 95100 to 95133, title 17, California Code of Regulations.

(19) "Energy" means any source of usable heat or power, such as fuel or electricity.

(20) "Energy efficiency" means a measure of the relative quantity of energy required to accomplish a task with the minimum energy expenditure.

(21) "Energy efficiency assessment" means an assessment as specified in section 95154.

(22) "Energy efficiency improvement project" means an undertaking involving such activities including, but not limited to, improvement in maintenance or other practices, monitoring systems, specific processes, or new or improved technologies, in order to increase energy efficiency at a facility.

(23) "Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

(24) "Equipment" means any stationary article, machine, or other contrivance, or combination thereof, used for specific purposes within a facility; equipment does not mean portable equipment, tactical support equipment, mobile vehicles, or generating units designated as backup or emergency generators in a permit issued by District.

(25) "Executive Officer" means the Executive Officer of the ARB or his or her delegate.

(26) "Facility" means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources located on one or more contiguous or adjacent properties, in actual physical contact or separated solely by a public roadway or other public right-of-way, and under common operational control, that emits or may emit any greenhouse gases.

(27) "Fluorine" means the most reactive nonmetallic element, generally designated with the symbol "F" and with an atomic weight of 18.9984.

(28) "Fuel" means solid, liquid, or gaseous combustible material used to create heat or power.

(29) "Global warming potential" or "GWP factor" means the radiative forcing impact of one mass-based unit of a given greenhouse gas relative to an equivalent unit of carbon dioxide over a given period of time.

(30) "Greenhouse gas" or "greenhouse gases" or "GHG" means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

(31) "Greenhouse gas source" means any physical unit, process, or other use or activity that emits a greenhouse gas.

(32) "Hydrocarbons" means chemical compounds containing predominantly carbon and hydrogen.

(33) "Hydrofluorocarbons" or "HFCs" means a class of GHGs primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

(34) "Hydrogen" means the lightest of all elements, designated by the symbol "H" and with an atomic weight of 1.00797; commonly exists as a gas consisting on the molecular level of two hydrogen atoms.

(35) "Kerosene" means a light distillate fuel that includes No.1-K and No. 2-K as well as other grades of range or stove oil that have properties similar to those of No. 1 fuel oil.

(36) "Kiln" means a device, including any associated preheater or precalciner device that produce clinker by heating limestone and other materials for subsequent production of Portland or other cement.

(37) "Kilowatt hour" or "kWh" means the electrical energy unit of measure equal to one thousand watts of power supplied to, or taken from, an electric circuit steadily for one hour. (A watt is a unit of electrical power equal to one ampere under pressure of one volt, or 1/746 horsepower.)

(38) "Methane" or "CH_4" means a colorless, odorless, flammable gas consisting on the molecular level of a single carbon atom and four hydrogen atoms.

(39) "Metric tonne" or "MT" or "tonne" means a common international measurement for the quantity of GHG emissions, equivalent to about 2204.6 pounds or 1.1 short tons.

(40) "Mobile combustion source" means a source of emissions resulting from combustion by a vehicle or other non-stationary, self-propelled combustion sources that produces greenhouse gas, criteria pollutant, and toxic air contaminant emissions. Mobile combustion sources include, but are not limited to, passenger cars, large/heavy duty truck cabs and chassis, light and medium duty trucks and vans, motorcycles, public transit buses, military tanks or other tracked military vehicles, mobile cranes, bulldozers, concrete mixers, street cleaners, golf carts, all terrain vehicles, trains, airplanes, boats, ships, implements of husbandry, and hauling equipment used inside and around airports, docks, depots, and industrial and commercial plants.

(41) "MMBtu" means million British thermal units. MMBtu = MWhr x 3.412.

(42) "MWhr" means megawatt hours; equal to one million watt hours.

(43) "Nitrous oxide" or "N_2O" means a GHG consisting at the molecular level of two nitrogen atoms and a single oxygen atom.

(44) "No. 1 fuel oil" means a light petroleum distillate fuel oil that meets the specifications of ASTM Specification D396-07.

(45) "North American Industry Classification System" or "NAICS" means a standard for use by Federal statistical agencies in classifying business establishments for the collection, analysis, and publication of statistical data related to the business economy of the United States.

(46) "Operational control" means the authority to introduce and implement operating, environmental, health, and safety policies. In any circumstance where this authority is shared among multiple entities, the entity holding the permit to operate from the District is considered to have operational control for purposes of this regulation.

(47) "Operator" means the entity having operational control of a facility, or other entity, from which an Assessment Report is required under this regulation.

(48) "Outside source" means a source of electricity not contained within a facility.

(49) "Oxides of nitrogen or NOx" means compounds of nitric oxide (NO), nitrogen dioxide (NO2), and other oxides of nitrogen, which are typically created during combustion processes and are major contributors to smog formation and acid deposition.

(50) "Perfluorocarbons" or "PFCs" means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

(51) "Petroleum" means an oily, thick, flammable liquid that is a mixture of various hydrocarbons occurring naturally within the earth and includes oil derived from tar sands, shale, and coal.

(52) "Petroleum refinery" or "refinery" means any facility engaged in producing gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, or other products through distillation of petroleum or through redistillation, cracking, rearrangement, or reforming of unfinished petroleum derivatives.

(53) "Portable" is as defined in title 17, California Code of Regulations, section 93116.2(a)(28).

(54) "Portland cement" means hydraulic cement (cement that not only hardens by reacting with water but also forms a water-resistant product) produced by pulverizing clinkers consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an inter-ground addition.

(55) "Process" means an action or series of actions performed in progressive and interdependent steps by equipment within a facility to produce or aid in producing a product such as cement, fuel, electricity, hydrogen, or other chemicals.

(56) "Process flow diagram" means a schematic representation of a facility which identifies the processes or systems within the facility and any interaction between the processes or systems such as transfer of material or energy from one process or system to another.

(57) "Project life" means the length of time an energy efficiency improvement project is expected to be employed.

(58) "Reactive Organic Gas" means a photochemically reactive chemical gas, composed of non-methane hydrocarbons, that may contribute to the formation of smog.

(59) "Residual fuel oil" means a general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations.

(60) "Source" means a piece of equipment, process or facility that emits greenhouse gases, criteria air pollutants or toxic air contaminants.

(61) "Sulfur hexafluoride" or "SF_6" means a GHG consisting on the molecular level of a single sulfur atom and six fluorine atoms.

(62) "System" means a group of interacting, interrelated, or interdependent processes within a facility.

(63) "Tactical support equipment" means equipment using a portable engine, including turbines, that meets military specifications, owned by the U.S. Department of Defense and/or the U.S. military services or its allies, and used in combat, combat support, combat service support, tactical or relief operations, or training for such operations. Examples include, but are not limited to, engines associated with portable generators, aircraft start carts, heaters and lighting carts.

(64) "Third party" means an entity hired by, but not otherwise affiliated with, a facility to conduct the facility's "energy efficiency assessment" as defined and/or develop the facility Assessment Report.

(65) "Ton" means a short ton equal to 2,000 pounds.

(66) "Toxic air contaminant" means a substance identified by the Air Resources Board as a toxic air contaminant pursuant to H&SC Section 39657.

(67) "Transportation fuel" means a fuel produced in a petroleum refinery to be sold into commerce for transportation purposes.

(68) "Watt hour" means a unit of energy, especially electrical energy, equal to the work done by one watt acting for one hour.

NOTE: Authority Cited: Sections 38510, 38530, 38560, 38562, 39600, 39601, 39659, and 41511, Health and Safety Code. Reference: Sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, 39003, 39500, 39600, 39601, 39659, and 4151, Health and Safety Code.

§ 95154. Energy Efficiency Assessment Requirements.

(a) ***Facility Energy Consumption and Emissions Analysis.*** The operator of each applicable facility described in section 95151(a) must conduct an energy consumption and emissions analysis that identifies the facility's processes and equipment types used in the processes, and provides facility energy consumption and resulting greenhouse gas, criteria air pollutant, and toxic air contaminant

emissions. The energy consumption and emissions analysis must be provided to the Executive Officer according to the reporting schedule identified in section 95155 and include the information below and any additional information specified in section 95155:

(1) Facility name, ARB identification number as assigned under the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, physical address, mailing address, geographic location (latitude and longitude at main gate or primary facility access point), NAICS code;
(2) Company name (if different than facility name);
(3) Name and contact information including email address and telephone number for the facility operator submitting the Assessment Report and for the person primarily responsible for preparing and submitting the Assessment Report, if different than the facility operator;
(4) If the assessment is conducted by a third party, the name and contact information including email address and telephone number of the company conducting and submitting the Assessment Report and the person primarily responsible for preparing the Assessment Report;
(5) Process flow diagram of the facility, identifying each process or system and its geographic location;
(6) Name and description of each process or system and the equipment types used in each;
(7) Types of energy used in each process or system (i.e., natural gas, purchased electricity, etc.), and whether the energy is purchased or produced by the facility;
(8) Facility energy use and emissions as indicated below:
    a. amount of fuel consumed in 2009 for each fuel type (in MMBtu);
    b. amount of electricity consumed in 2009 (in MMBtu);
    c. total energy consumption (sum of a. and b. above);
    d. greenhouse gas emissions in 2009 reported as CO_2e emissions resulting from the fuel consumed in a. above and the electricity consumed in b. above;
    e. criteria air pollutant emissions in 2009 reported by the facility to the District, except as provided in (10) below, as required by Health and Safety Code, section 40701(g), and District rules;
    f. toxic air contaminant emissions reported by the facility to the District in 2009, except as provided in (10) below, as required by Health and Safety Code, sections 44340, 44341, and 44344 and the Emission Inventory Criteria and Guidelines Report for the Air Toxics "Hot Spots" Program, Title 17, California Code of Regulations, section 93300.5.
(9) Facility energy use and emissions reported in (8)a. through (8)d. above must be consistent with the facility's verified or certified greenhouse gas emissions data report submitted in accordance with the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, sections 95100 to 95133, title 17, California Code of Regulations for the 2009 calendar year;

(10) Upon approval from the Executive Officer, the operator may provide the criteria and or toxics emissions inventory data indicated in (8) from a different calendar year(s) or a three-year average. Any request for approval for submittal of emissions inventory data from alternative calendar years or a three-year average must be made in writing by the operator and submitted to the Executive Officer no later than December 1, 2011. The Executive Officer has 30 days to approve or disapprove the request and will notify the operator in writing of the decision.

(b) ***Energy Efficiency Improvement Analysis.*** The operator of each applicable facility described in section 95151(a) must conduct an analysis of the energy efficiency improvement opportunities that exist at the facility. The energy efficiency improvement analysis must:

1. Identify potential improvement projects for equipment, processes, or systems that cumulatively account for at least 95 percent of the facility's total greenhouse gas emissions reported in section 95154(a);
2. Include a comprehensive assessment of potential energy efficiency improvement opportunities;
3. Where appropriate or applicable, a facility operator may use an energy assessment conducted for their facility by a state- or federally-sponsored energy assessment program in order to meet applicable portions of the requirements in this subsection;.
4. Be provided to the Executive Officer according to the reporting schedule identified in section 95155 and include information below and any additional information specified in section 95155 for each potential improvement evaluated:

    a. Existing facility equipment, process, or system involved;
    b. Type of potential improvement, including, but not limited to, equipment upgrades or modifications, process changes, changes to operating procedures or maintenance practices, or investment in new technologies; potential improvement projects should encompass low-cost projects that could be implemented quickly to mid- and long-term projects requiring higher capital expenditures and that may have more extensive facility impacts; emerging technologies that are not yet commercially available may also be considered;
    c. Summary description of each potential improvement, including but not limited to, a description of the system(s) involved and the energy efficiency issues that have been identified, and a description of how the improvement would benefit energy efficiency;
    d. Status of the improvement (i.e., under investigation, scheduled, on-going, completed, or not implementing);
    e. For any improvement projects not being implemented, provide a description of the rationale for not implementing the project;
    f. Estimated time frame for the project implementation and the estimated completion date for those that are under investigation, scheduled, or on-

going, and the actual completion date for those that have been implemented;

g. Estimated total one-time budgetary costs (in 2010 dollars), including, but not limited to, capital costs of equipment, installation, design, construction, and permits;
h. Estimated total average recurring annual budgetary costs (in 2010 dollars), including, but not limited to, operation and maintenance;
i. Estimated project life;
j. Estimated average annual energy savings;
k. Estimated associated average annual GHG emission reductions and criteria pollutant and toxic air contaminant emission impacts;
l. Estimated annual cost savings (in 2010 dollars), if applicable;
m. Specification in detail of the estimation method, source test method, or other measurement method that was used to quantify the estimated GHG, criteria pollutant, and toxic air contaminant emission impacts in (10) above. The estimation method must include, but is not limited to, emission factors, control efficiency assumptions, and any other key assumptions used. The Executive Officer may work with the facility operator to determine appropriate values and may provide guidance for specific methodologies to be used;
n. Identification of any District air quality permit requirements, California Environmental Quality Act requirements, and other implementation considerations (including, but not limited to building, zoning, operational, safety, noise, water, and other environmental impacts).

(c) ***Alternative Approach Using Energy Consumption.*** For the Energy Efficiency Improvement Analysis in (b) above, the operator may identify potential improvement projects for equipment, processes, or systems that cumulatively account for at least 95 percent of the facility's total energy consumption as reported in section 95154(a), provided that the Executive Officer finds that this approach is equivalent to the approach contained in section 95154(b). The operator must identify the equipment excluded from the analysis by equipment type and numbers of pieces of equipment per type.

(d) ***Fuel Use Measurement Accuracy.*** The operator must employ the procedures for fuel use data measurements as required by the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, sections 95100 to 95133, title 17, California Code of Regulations.

NOTE: Authority Cited: Sections 38510, 38530, 38560, 38562, , 39600, 39601, 39659, and 41511, Health and Safety Code. Reference: Sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, , 39003, 39500, 39600, 39601, 39659, and 4151, Health and Safety Code.

§ 95155. Reporting Requirements.

The operator of each applicable facility described in section 95151(a) must submit the data specified in section 95154 and the following information, collectively referred to as the Assessment Report, to the Executive Officer according to the following:

(a) By December 15, 2011, the operator of each applicable facility described in section 95151(a) must submit the Assessment Report to the Executive Officer.

(b) The facility operator must sign a statement certifying that the information contained in the Assessment Report is true, accurate, and complete and that the operator is duly authorized to represent the facility on all matters related to the Assessment Report.

(c) If the Assessment Report is conducted by a third party, the third party assessor must sign a statement certifying that the information contained in the Assessment Report is true, accurate, and complete and that the operator is duly authorized to represent the third party on all matters related to the Assessment Report.

(d) The Assessment Report must be submitted to the Air Resources Board using the following address:

California Air Resources Board
Stationary Source Division, Energy Assessments
1001 I Street
P.O. Box 2815
Sacramento, California 95812-2815

(e) An alternative method of submittal, including electronic submittals, may be approved by the Executive Officer.

NOTE: Authority Cited: Sections 38510, 38530, 38560, 38562, 38580, 39600, 39601, 39659, and 41511, Health and Safety Code. Reference: Sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, 38580, 39003, 39500, 39600, 39601, 39659, and 4151, Health and Safety Code.

§ 95156. Document Retention, Recordkeeping, and Additional Data Requirements.

(a) ***General Requirements.*** The operator must establish and document a system that provides clarity, transparency, and completeness of data and processes sufficient to facilitate replication of the Assessment Report information as specified by this article. The operator must complete an Assessment Report that is in conformance with the data collection methodologies specified in their Assessment Report.

(b) ***Document Retention and Recordkeeping.*** The operator must retain documents regarding the procedures used to obtain the data supplied as specified by this article for a minimum of five years following submittal of the Assessment Report.

(c) ***Additional Data Requirements.*** Upon written request by ARB, the operator must within 30 days of receipt of the written request provide ARB access to all documents, including data and methodologies, used to develop the Assessment Report.

NOTE: Authority Cited: Sections 38510, 38530, 38560, 38562, 38580, 39600, 39601, 39659, and 41511, Health and Safety Code. Reference: Sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, 38580, 39003, 39500, 39600, 39601, 39659, and 4151, Health and Safety Code.

§ 95157. Compliance Extension for Assessment Report Submittal.

A facility operator may be granted a compliance extension to the Assessment Report submittal deadline specified in section 95155(a) as provided below.

(a) The Executive Officer may grant, in writing, up to a 90-day compliance extension upon determining the following conditions have been met:

(1) The facility operator has requested the compliance extension by November 15, 2011;
(2) The facility operator has described the reason(s) for the request for a compliance extension and has identified the additional time required for completion of the Assessment Report; and
(3) The requested compliance extension does not exceed 90 days.

NOTE: Authority Cited: Sections 38510, 38530, 38560, 38562, 38580, 39600, 39601, 39659, and 41511, Health and Safety Code. Reference: Sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, 38580, 39003, 39500, 39600, 39601, 39659, and 4151, Health and Safety Code.

§ 95158. Assessment Report Review, Validation, and Public Disclosure.

(a) Within 45 days of receipt of an Assessment Report, the Executive Officer will review the Assessment Report and determine whether it is complete as specified in section 95154, and whether the data submitted is valid and calculated using emissions calculation methodologies provided with the Assessment Report as required in section 95154(b) and using previously reported data, as required in section 95154(a). The Executive Officer will notify the facility operator of any deficiencies in the Assessment Report. The facility operator and the Executive Officer may mutually agree to a longer time period for reaching a decision on the completeness of the Assessment Report, and additional supporting documentation may be submitted by the facility operator before the Executive Officer deems the Assessment Report to be complete. If the Assessment Report is deemed incomplete, the Executive Officer will notify the facility operator in writing, via either an electronic submission or hard copy, of the determination of an incomplete Assessment Report and may require the operator to conduct a third-party assessment following the requirements in section 95159.

(b) The Executive Officer will establish an Internet site ("Assessment Report Internet site") in which all Assessment Reports will be made available to the public. Completed Assessment Reports submitted to ARB will be posted on the Assessment Report Internet site by April 30, 2012.

NOTE: Authority Cited: Sections 38510, 38530, 38560, 38562, 38580, 39600, 39601, 39659, and 41511, Health and Safety Code. Reference: Sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, 38580, 39003, 39500, 39600, 39601, 39659, and 4151, Health and Safety Code.

§ 95159. Third Party Assessment Report.

(a) In the event that an operator is required per section 95158(a) to complete a new Assessment Report, conducted by a third party, all requirements of sections 95154 through 95156 will apply.

(1) Within 60 days of receiving notification from ARB of its determination of an incomplete Assessment Report, the operator must submit a written application to the Executive Officer for approval of the operator's chosen third party assessor. The application must include the following:

a. third party assessor company name;
b. third party assessor contact name, title, address, phone number, and email address;
c. demonstration of the third party assessor's qualifications to effectively conduct a facility-wide Assessment Report as required by this regulation;
d. a cost estimate from the third party assessor for conducting the assessment;

e. a signed statement from the third party assessor that they have no interest, material or otherwise, in the facility or relationship with facility personnel or owners that could be construed as adversely affecting their impartiality; and
f. a signed statement from the facility operator that they have no interest, material or otherwise, in the third party assessor or relationship with the third party assessor's company or personnel that could be construed as adversely affecting their impartiality;

(2) The Executive Officer will approve the third party assessor selected by the facility upon determining that the requirements of (a)(1) above have been met.

(3) The operator must submit the completed third party Assessment Report within 90 days of receiving Executive Officer approval of the third party assessor.

NOTE: Authority Cited: Sections 38510, 38530, 38560, 38562, 38580, 39600, 39601, 39659, and 41511, Health and Safety Code. Reference: Sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, 38580, 39003, 39500, 39600, 39601, 39659, and 4151, Health and Safety Code.

§ 95160. Confidentiality.

(a) Emissions data submitted to the ARB under this article is public information and would not be designated as confidential.

(b) Any entity submitting information to the ARB pursuant to this article may designate information that is not emissions data as confidential because they believe it to be a trade secret or otherwise exempt from public disclosure under the California Public Records Act (Government Code section 6250 et seq.). All such requests for confidentiality will be handled in accordance with the procedures specified in title 17, California Code of Regulations, sections 91000 to 91022.

NOTE: Authority Cited: Sections 38510, 38530, 38560, 38562, 39600, 39601, 39659, and 41511, Health and Safety Code. Reference: Sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, 39003, 39500, 39600, 39601, 39659, and 4151, Health and Safety Code.

§ 95161. Enforcement.

(a) Submission of inaccurate information to the Executive Officer or an agent or representative of the Air Resources Board, will constitute a separate violation of the requirements of this article for each day after the information has been received by the Executive Officer.

(b) Failure to submit any report or to include in a report all information required by this article, or late submittal of the report, will constitute a separate violation of this article for each day that the report has not been submitted beyond the required submittal date, as specified in section 95155. For the purposes of this section, "report" means any document required to be submitted by this article.

NOTE: Authority Cited: Sections 38510, 38530, 38560, 38562, 38580, 39600, 39601, 39659, and 41511, Health and Safety Code. Reference: Sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, 38580, 39003, 39500, 39600, 39601, 39659, and 4151, Health and Safety Code.

§ 95162. Severability.

Each part of this article will be deemed severable, and in the event that any provision of this article is held to be invalid, the remainder of this article will continue in full force and effect.

NOTE: Authority Cited: Sections 38510, 38530, 38560, 38562, 39600, 39601, 39659, and 41511, Health and Safety Code. Reference: Sections 38501, 38505, 38510, 38530, 38550, 38551, 38560, 38561, 38562, 38563, 39003, 39500, 39600, 39601, 39659, and 4151, Health and Safety Code.

Appendix B

Methodology for Presenting Toxic Emissions From Facilities Subject to the Proposed Regulation

-This page is intentionally blank-

Appendix B

Methodology for Presenting Toxic Emissions From Facilities Subject to the Proposed Regulation

This appendix summarizes the methodology used for determining the more prevalent toxic substances that are associated with each source category (i.e., cement plants, electricity generation, hydrogen plants, mineral plants, oil and gas extraction, and refineries). For each of the source categories, staff used the 2008 emissions data reported to the ARB from the approximately 60 impacted facilities. The reported emissions for each substance were weighted based on their carcinogenic and non-carcinogenic health values and their potential for noninhalation impacts. Each substance was given a score and ranked within each source category. The substances with the highest score were chosen as the most prevalent toxic substances. The details of the methodology to determine the most prevalent toxic substances are described below.

Methodology:

To calculate the individual substance scores within each source category, the sum of the emissions (annual and maximum hourly) and OEHHA's health values (cancer, noncancer chronic and acute) were used to obtain a substance score. The emissions data were obtained from the California Emissions Inventory Database and Reporting System (CEIDARS) for the year 2008. The health values used in the scoring calculations came from the OEHHA Air Toxics Hot Spots Program Risk Assessment Guideline Manual for Preparation of Health Risk Assessments and the Hot Spots Analysis and Reporting Program (HARP) Software. (OEHHA, 2003) Table B-1 provides a summary of substance scores for each source category with a total weighted score greater than approximately 10 with the exception of Hydrogen Plants. The total score at Hydrogen Plants only includes scoring from annual emissions and may be higher if maximum hourly emissions were reported.

The reported emissions were weighted by their respective cancer and noncancer health factors using the equations below. The equations used to weight the emissions were obtained from the CAPCOA Facility Prioritization Guidelines. (CAPCOA,1990) Note that no receptor proximity adjustments were included in these calculations and that acute and chronic noncancer scores were calculated separately as opposed to together as done in the prioritization guidelines.

This scoring procedure is intended to rank the reported substances based on emissions and associated health effects. This is a commonly used and simple method for prioritizing substances. The results from this scoring procedure do not reflect the potential health impacts one might be estimated to endure from exposure to facility emissions. Therefore, these scoring results should not be interpreted as a potential risk

estimate or as risk assessment results. Health risk assessments (HRAs) require additional information and must undergo further analysis and modeling. Examples of additional information that would be included in an HRA include the location and release characteristics of each substance and several exposure assumptions.

Cancer Effects:

$CS = (Ec)(Pc)(1.7 \times 10^3)$

Where:
CS = carcinogenic pollutant score
Ec = emissions of substance with carcinogenic health effects (lbs/year)
Pc = unit risk factor for substance
1.7×10^3 = normalization factor (standardizes score to whole number scale)

Noncancer Effects (Chronic):

NCc = [{(Et/8760)/Pt}/150]

Where:
NCc = noncancer chronic pollutant score
E_t = emissions of substance (lbs/year) with noncancer chronic health effects
(Note: 8760 hours assumes continuous operations)
P_t = Chronic Reference Exposure Level (REL) for substance
150 = normalization factor (standardizes score to whole number scale)

Noncancer Effects (Acute):

NCa = [(Et/Pt)/1500]

Where:
NCa = noncancer acute pollutant score
E_t = emissions of substance (max lb/hr) with acute health effects
(Note: not all facilities reported maximum hourly emissions)
P_t = Acute Reference Exposure Level (REL) for substance
1500 = normalization factor (standardizes score to whole number scale

Table B-1: Summary of Pollutant Scores for Each Source Category[1]

Pollutant ID Number[2]	Pollutant Name	Reported Emissions (lbs/yr)	Reported Maximum Hourly Emissions	Total Score[3]	Cancer Score[4]	Chronic Score[4]	Acute Score[4]	Oral CSF[5]	Oral REL[5]
	Cement Plants								
18540299	Chromium, hexavalent (& compounds)	18	0.001	4705	4703	1.6			X
7440382	Arsenic	438	0.004	2982	2456	500	26	X	X
9901	Diesel engine exhaust, particulate matter (Diesel PM)	3398	21	1745	1733	12			
71432	Benzene	23683	0.82	1176	1168	6.8	0.95		
7664417	Ammonia	63686	2403	1132		5.5	1126		
7440439	Cadmium	118	0.001	946	845	101			X
50000	Formaldehyde	68337	1.3	863	697	130	36		
10102440	Nitrogen dioxide	7171	254	809			809		
7647010	Hydrochloric acid	396728	48	789		755	34		
7439976	Mercury	1005	0.08	786		574	212		X
1080	Dibenzofurans (chlorinated) {PCDFs} [Treated as 2378TCDD for HRA]	0.01	0.00000003	750	745	4.9		X	X
7439965	Manganese	2057	0.04	391		391			
7440417	Beryllium	50	0.0001	326	204	122			X
1175	Silica, crystalline (respirable)	49379	52	282		282			
91203	Naphthalene	3262	0.04	195	189	6.2			
7446095	Sulfur dioxide	755	85	193			193		
32774166	3,3',4,4',5,5'-Hexachlorobiphenyl {PCB 169}	0.21	0.00003	139	138	0.91		X	X
106898	Epichlorohydrin	3001	Not reported	134	117	17			
7440020	Nickel	154	0.01	123	68	53	1.5		X

1. All numbers are rounded.
2. Pollutant identification (ID) number is the Chemical Abstract Service (CAS) number where available, or an ARB-assigned 4-digit emittent identification number. Source is AR8's CEIDARS Database and the Emission Inventory Criteria and Guidelines (September 2007).
3. Total Score = Cancer Score + Noncancer (Chronic) + Noncancer (Acute).
4. Scores are blank when no emissions are reported or no health value exists to score that substance.
5. Oral CSF = Oral Cancer Slope factor; Oral REL = Oral Reference Exposure Level. X indicates presence of a factor in the OEHHA Air Toxics Hot Spot Program Risk Assessment Guideline (August 2003).

Table B-1: Summary of Pollutant Scores for Each Source Category[1] (Continued)

Pollutant ID Number[2]	Pollutant Name	Reported Emissions (lbs/yr)	Reported Maximum Hourly Emissions	Total Score[3]	Cancer Score[4]	Chronic Score[4]	Acute Score[4]	Oral CSF[5]	Oral REL[5]
	Cement Plants (continued)								
75070	Acetaldehyde	19474	0.97	95	89	2.4	3.1		
107028	Acrolein	674	0.08	82		33	49		
75014	Vinyl chloride	555	0.09	74	74		0.001		
106990	1,3-Butadiene	230	0.01	66	66	0.20			
1151	PAHs, total, w/o individ. components reported [Treated as B(a)P for HRA]	27	0.0004	51	51			X	
106934	Ethylene dibromide {EDB}	314	0.01	45	38	6.7			
1332214	Asbestos	60	Not reported	19	19				
7439921	Lead	866	0.02	18	18			X	
1086	Dioxins, total, w/o individ. isomers reported {PCDDs} [Treat as 2378TCDD for HRA]	0.0003	0.0000001	17	17	0.11		X	X
106467	p-Dichlorobenzene	873	0.01	16	16	0.02			
100447	Benzyl chloride	164	0.02	14	14		0.10		
57117314	2,3,4,7,8-Pentachlorodibenzofuran	0.0003	0.000000001	11	11	0.07		X	X
53703	Dibenz[a,h]anthracene	5.0	0.000002	10	10			X	
	Electricity Generation								
7440020	Nickel	53	4.3	1124	24	18	1082		X
50000	Formaldehyde	44444	19	1055	453	85	517		
71432	Benzene	10039	1.2	499	495	2.9	1.4		

1. All numbers are rounded.
2. Pollutant identification (ID) number is the Chemical Abstract Service (CAS) number where available, or an ARB-assigned 4-digit emittent identification number. Source is ARB's CEIDARS Database and the Emission Inventory Criteria and Guidelines (September 2007).
3. Total Score = Cancer Score + Noncancer (Chronic) + Noncancer (Acute).
4. Scores are blank when no emissions are reported or no health value exists to score that substance.
5. Oral CSF = Oral Cancer Slope factor; Oral REL = Oral Reference Exposure Level. X indicates presence of a factor in the OEHHA Air Toxics Hot Spot Program Risk Assessment Guideline (August 2003).

Table B-1: Summary of Pollutant Scores for Each Source Category[1] (Continued)

Pollutant ID Number[2]	Pollutant Name	Reported Emissions (lbs/yr)	Reported Maximum Hourly Emissions	Total Score[3]	Cancer Score[4]	Chronic Score[4]	Acute Score[4]	Oral CSF[5]	Oral REL[5]
	Electricity Generation (continued)								
7440382	Arsenic	3.2	0.06	495	18	3.7	473	X	X
18540299	Chromium, hexavalent (& compounds)	1.3	0.01	342	342	0.11			X
1080	Dibenzofurans (chlorinated) {PCDFs} [Treated as 2378TCDD for HRA]	0.004	0.0000004	285	283	1.9		X	X
107028	Acrolein	1313	0.16	163		64	99		
91203	Naphthalene	2210	0.33	132	128	4.2			
7439965	Manganese	458	0.19	87		87			
1151	PAHs, total, w/o individ. components reported [Treated as B(a)P for HRA]	46	Not reported	87	87			X	
7664417	Ammonia	509725	36	61		44	17		
9901	Diesel engine exhaust, particulate matter (Diesel PM)	109	5.5	55	55	0.37			
7440439	Cadmium	4.7	0.003	37	33	4.0			X
106934	Ethylene dibromide {EDB}	232	Not reported	33	28	5.0			
7439976	Mercury	6.7	0.01	30		3.8	26		X
56235	Carbon tetrachloride	190	Not reported	14	14	0.08			
75014	Vinyl chloride	97	Not reported	13	13				
7783064	Hydrogen sulfide	6857	Not reported	12		12			
75070	Acetaldehyde	1872	0.29	9.8	8.6	0.23	0.94		

1. All numbers are rounded.
2. Pollutant identification (ID) number is the Chemical Abstract Service (CAS) number where available, or an ARB-assigned 4-digit emittent identification number. Source is ARB's CEIDARS Database and the Emission Inventory Criteria and Guidelines (September 2007).
3. Total Score = Cancer Score + Noncancer (Chronic) + Noncancer (Acute).
4. Scores are blank when no emissions are reported or no health value exists to score that substance.
5. Oral CSF = Oral Cancer Slope factor; Oral REL = Oral Reference Exposure Level. X indicates presence of a factor in the OEHHA Air Toxics Hot Spot Program Risk Assessment Guideline (August 2003).

Table B-1: Summary of Pollutant Scores for Each Source Category[1] (Continued)

Pollutant ID Number[2]	Pollutant Name	Reported Emissions (lbs/yr)	Reported Maximum Hourly Emissions	Total Score[3]	Cancer Score[4]	Chronic Score[4]	Acute Score[4]	Oral CSF[5]	Oral REL[5]
	Hydrogen Plants								
1151	PAHs, total, w/o individ. components reported [Treated as B(a)P for HRA]	2.7	Not reported	5.1	5.1			X	
71432	Benzene	93	Not reported	4.6	4.6	0.03			
7440439	Cadmium	0.47	Not reported	3.8	3.4	0.40			X
7440020	Nickel	4.5	Not reported	3.5	2.0	1.5			X
50000	Formaldehyde	278	Not reported	3.3	2.8	0.53			
7440382	Arsenic	0.40	Not reported	2.7	2.2	0.46		X	X
7664417	Ammonia	13816	Not reported	1.2		1.2			
	Mineral Plants								
7783064	Hydrogen sulfide	757956	97	4766		1298	3468		
7440439	Cadmium	26	0.005	204	182	22			X
1086	Dioxins, total, w/o individ. isomers reported {PCDDs} [Treat as 2378TCDD for HRA]	0.002	0.00002	100	99	0.65		X	X
1016	Arsenic compounds (inorganic)	5.8	0.01	99	33	6.7	59	X	X
7664939	Sulfuric acid	3557	0.44	66		61	5.6		
1080	Dibenzofurans (chlorinated) {PCDFs} [Treated as 2378TCDD for HRA]	0.001	0.00003	61	60	0.40		X	X
7439976	Mercury	5.9	0.01	24		3.4	21		X
50000	Formaldehyde	264	0.44	15	2.7	0.50	12		
71432	Benzene	146	0.97	8.3	7.2	0.04	1.1		

1. All numbers are rounded.
2. Pollutant identification (ID) number is the Chemical Abstract Service (CAS) number where available, or an ARB-assigned 4-digit emittent identification number. Source is ARB's CEIDARS Database and the Emission Inventory Criteria and Guidelines (September 2007).
3. Total Score = Cancer Score + Noncancer (Chronic) + Noncancer (Acute).
4. Scores are blank when no emissions are reported or no health value exists to score that substance.
5. Oral CSF = Oral Cancer Slope factor; Oral REL = Oral Reference Exposure Level. X indicates presence of a factor in the OEHHA Air Toxics Hot Spot Program Risk Assessment Guideline (August 2003).

Table B-1: Summary of Pollutant Scores for Each Source Category[1] (Continued)

Pollutant ID Number[2]	Pollutant Name	Reported Emissions (lbs/yr)	Reported Maximum Hourly Emissions	Total Score[3]	Cancer Score[4]	Chronic Score[4]	Acute Score[4]	Oral CSF[5]	Oral REL[5]
	Oil and Gas Production								
9901	Diesel engine exhaust, particulate matter (Diesel PM)	23	2.1	12	12	0.08			
7664417	Ammonia	67762	3.5	7.4		5.8	1.6		
	Refineries								
18540299	Chromium, hexavalent (& compounds)	14	0.00002	3557	3556	1.2			X
106990	1,3-Butadiene	6403	Not reported	1856	1850	5.5			
71432	Benzene	33097	0.07	1641	1632	9.4	0.08		
7440439	Cadmium	180	0.0003	1435	1282	154			X
7440020	Nickel	1610	0.21	1315	712	552	52		X
50000	Formaldehyde	107298	0.06	1300	1094	204	1.6		
50328	Benzo[a]pyrene	520	Not reported	973	973			X	
7440382	Arsenic	83	Not reported	563	468	95		X	X
1151	PAHs, total, w/o individ. components reported [Treated as B(a)P for HRA]	179	Not reported	335	335			X	
91203	Naphthalene	5487	0.07	328	317	10			
9901	Diesel engine exhaust, particulate matter (Diesel PM)	380	2.0	195	194	1.3			
7439965	Manganese	794	0.04	151		151			
7664417	Ammonia	1561712	0.29	134		134	0.14		

1. All numbers are rounded.
2. Pollutant identification (ID) number is the Chemical Abstract Service (CAS) number where available, or an ARB-assigned 4-digit emittent identification number. Source is ARB's CEIDARS Database and the Emission Inventory Criteria and Guidelines (September 2007).
3. Total Score = Cancer Score + Noncancer (Chronic) + Noncancer (Acute).
4. Scores are blank when no emissions are reported or no health value exists to score that substance.
5. Oral CSF = Oral Cancer Slope factor; Oral REL = Oral Reference Exposure Level. X indicates presence of a factor in the OEHHA Air Toxics Hot Spot Program Risk Assessment Guideline (August 2003).

Table B-1: Summary of Pollutant Scores for Each Source Category[1] (Continued)

Pollutant ID Number[2]	Pollutant Name	Reported Emissions (lbs/yr)	Reported Maximum Hourly Emissions	Total Score[3]	Cancer Score[4]	Chronic Score[4]	Acute Score[4]	Oral CSF[5]	Oral REL[5]
	Refineries (continued)								
1080	Dibenzofurans (chlorinated) {PCDFs} [Treated as 2378TCDD for HRA]	0.002	Not reported	122	121	0.80		X	X
7440417	Beryllium	19	0.00003	121	76	45			X
7439976	Mercury	125	0.002	77		71	6.0		X
7647010	Hydrochloric acid	18286	36	60		35	26		
7664939	Sulfuric acid	3208	Not reported	55		55			
7783064	Hydrogen sulfide	12011	0.17	27		21	6.2		
79016	Trichloroethylene	6345	Not reported	22	22	0.18			
7782505	Chlorine	219	0.004	19		19	0.03		
111308	Glutaraldehyde	84	Not reported	18		18			

1. All numbers are rounded.
2. Pollutant identification (ID) number is the Chemical Abstract Service (CAS) number where available, or an ARB-assigned 4-digit emittent identification number. Source is ARB's CEIDARS Database and the Emission Inventory Criteria and Guidelines (September 2007).
3. Total Score = Cancer Score + Noncancer (Chronic) + Noncancer (Acute).
4. Scores are blank when no emissions are reported or no health value exists to score that substance.
5. Oral CSF = Oral Cancer Slope factor; Oral REL = Oral Reference Exposure Level. X indicates presence of a factor in the OEHHA Air Toxics Hot Spot Program Risk Assessment Guideline (August 2003).