California Environmental Protection Agency

Air Resources Board

LOCATION:
Air Resources Board
Auditorium
9530 Telstar Avenue
El Monte, California 91731

PUBLIC MEETING AGENDA

This facility is accessible by public transit. For transit information, call: Metropolitan Transit Authority (MTA) at 1-800-COMMUTE, website: www.mta.net (This facility is accessible to persons with disabilities.)

DECEMBER 6 & 7, 2007

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

December 6, 2007
9:00 a.m.

Item #

07-12-1: Health Update: A Review of Chronic Air Pollution Exposure and Adverse Effects on the Brain

Staff will present a review of recent studies investigating the relationship between air pollution and adverse effects on the brain. The studies show that chronic exposure to air pollution is associated with inflammation and structural damage to the brain. These findings suggest that health impacts associated with exposure to air pollution are more far-reaching than previously thought.

07-12-8: Public Meeting to Consider Appointment of Replacement Member to the Economic and Technology Advancement Advisory Committee

The representative to the Assembly Bill 32 Economic and Technology Advancement Advisory Committee from the California Chamber of Commerce has resigned from the Committee. Staff will ask the Board to approve the appointment to the Committee of Ms. Amisha Patel of the California Chamber of Commerce, effective immediately.

07-12-2: Public Meeting to Update the Board on a Climate Change Science Update: Action at a Local Level

Staff will provide an update on how local cities and counties are implementing a variety of climate action strategies to reduce greenhouse gas emissions.

07-12-3: Public Hearing to Consider Adoption of a Regulation for the Mandatory Reporting of Greenhouse Gas Emissions

Staff will present a proposed regulation establishing a mandatory greenhouse gas (GHG) reporting program for California. This regulation is being developed pursuant to requirements of the California Global Warming Solutions Act (AB 32, Statutes of 2006, Chapter 488). Under the proposed regulation the most significant sources of GHGs in the State would be required to report their GHG emissions annually, beginning in 2009. The proposed regulation includes detailed specifications for emissions calculations, reporting, and verification of GHG emission estimates. Key industrial sectors subject to reporting include the electricity sector, oil refineries, cement plants, cogeneration facilities, and other significant industrial sources of GHGs.

07-12-4: Public Meeting to Consider the 1990 Statewide GHG Emissions Level and 2020 Emissions Limit

*AB 32 requires ARB to determine what the statewide GHG emissions level was in 1990 and approve a statewide greenhouse gas emissions limit equivalent to that level to be achieved by 2020. Beginning with the California Energy Commission's "*Inventory of California Greenhouse Gas Emissions and Sinks: 1990-2004,*" staff undertook an extensive review of the methods and data used to develop the statewide GHG inventory, with particular focus on the 1990 statewide GHG emissions level. After completing a comprehensive review and update process, ARB staff is proposing for Board approval a 1990 statewide GHG level and 2020 limit of 427 million metric tonnes of carbon dioxide equivalent.*

07-12-5: Public Hearing to Consider Adoption of the Gaseous Pollutant Measurement Allowances for California's Heavy-Duty Diesel In-Use Compliance Regulation

In 2006, the Board adopted a new heavy-duty diesel in-use compliance regulation and test procedures, known as the manufacturer-run heavy-duty diesel in-use testing program. All testing in this program will be conducted by engine manufacturers with portable emission measurement systems (PEMS). ARB, the U. S. Environmental Protection Agency (U.S. EPA), and the Engine Manufacturers Association (EMA) agreed to fund a test program to determine a "measurement allowance" for each gaseous pollutant to account for any potential difference in measurement accuracy between measurements made with PEMS in the field and laboratory grade analyzers in the laboratory. The test program has been completed and ARB, U.S. EPA, and EMA have agreed on the appropriate measurement allowances.

07-12-6: Public Hearing to Consider the Adoption of Proposed Regulations to Reduce Emissions from Diesel Auxiliary Engines on Ocean-Going Vessels while at Berth at a California Port

The proposed regulations would require ocean-going vessels to reduce their emissions while docked at a California port.

07-12-10: Public Meeting to Consider Options Regarding the Requested Disclosure of Zero Emission Vehicle (ZEV) Credit Data Based on Submittals by Vehicle Manufacturers Who Have Designated the Data as Confidential Trade Secret Information

The staff will describe the potential options in responding to public requests for disclosure of information compiled by ARB from submittals by vehicle manufacturers of information on their production of ZEVs, partial ZEV allowance vehicles (PZEVs) and advanced technology PZEVs, and any exchanges of ZEV credits. This information, which has been claimed to be trade secret by all large volume manufacturers, is relevant to the upcoming rulemaking on proposed amendments to the ZEV regulations.

December 7, 2007
8:30 a.m.

Item #

07-12-9: Report to the Board on the Nonattainment Area Recommendations for the Revised Federal PM2.5 24-Hour Standard

Staff will present recommendations to the Board on proposed nonattainment areas for the revised federal PM2.5 24-hour standard. The 24-hour PM2.5 standard was recently revised from 65 ug/m^3 to 35 ug/m^3. These recommendations are to be submitted to the U.S. Environmental Protection Agency by December 18, 2007.

07-12-7: Public Hearing to Consider the Adoption of Proposed Regulation to Control Emissions from In-Use On-Road Diesel-Fueled Heavy-Duty Drayage Trucks at Ports and Intermodal Rail Yard Facilities

The proposed regulation would require on-road heavy-duty diesel trucks servicing California's ports and intermodal rail yards to reduce their emissions by meeting specified emission standards.

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 litigation:

Central Valley Chrysler-Jeep, Inc. et al. v. Witherspoon, U.S. District Court (E.D. Cal. – Fresno), No. CIV-F-04-6663 REC LJO.

Fresno Dodge, Inc. et al. v. California Air Resources Board and Witherspoon, Superior Court of California (Fresno County), Case No. 04CE CG03498.

General Motors Corp. et al. v. California Air Resources Board and Witherspoon, Superior Court of California (Fresno County), No. 05CE CG02787.

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 that 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
1001 I Street, 23rd Floor, Sacramento, CA 95814

(916) 322-5594
FAX: (916) 322-3928
ARB Homepage: www.arb.ca.gov

To request special accommodation or language needs, please contact the following:

- **For individuals with sensory disabilities, this document is available in Braille, large print, audiocassette or computer disk. Please contact ARB's Disability Coordinator at 916-323-4916 by voice or through the California Relay Services at 711, to place your request for disability services.**
- **If you are a person with limited English and would like to request interpreter services to be available at the Board meeting, please contact ARB's Bilingual Manager at 916-323-7053.**

THE AGENDA ITEMS LISTED ABOVE MAY BE CONSIDERED IN A DIFFERENT ORDER AT THE BOARD MEETING. THOSE ITEMS ABOVE THAT ARE NOT COMPLETED ON DECEMBER 6 WILL BE HEARD BEGINNING AT 8:30 A.M. ON DECEMBER 7.

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

California Environmental Protection Agency

Air Resources Board

PUBLIC MEETING AGENDA

INDEX

LOCATION:
Air Resources Board
Auditorium
9530 Telstar Avenue
El Monte, California 91731

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December 6, 2007
9:00 a.m.

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December 7, 2007
8:30 a.m.

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TITLE 17. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER ADOPTION OF A REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

The Air Resources Board (the Board or ARB) will conduct a public meeting at the time and place noted below to consider the adoption of regulations to require mandatory reporting of greenhouse gas (GHG) emissions for California facilities. This regulation is being developed pursuant to requirements of the California Global Warming Solutions Act (AB 32, Statutes of 2006, Chapter 488).

DATE: December 6, 2007

TIME: 9:00 a.m.

PLACE: Air Resources Board
Auditorium
9530 Telstar Avenue
El Monte, CA 91731

This meeting location may change. This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., December 6, 2007, and may continue at 9:00 a.m., December 7, 2007. This item may not be considered until December 7, 2007. Please consult the agenda for the meeting, which will be available at least 10 days before December 6, 2007, to determine the location and day on which this item will be considered.

For individuals with sensory disabilities, this document is available in Braille, large print, audiocassette, or computer disk. Please contact ARB's Disability Coordinator at (916) 323-4916 by voice or through the California Relay Services at 711, to place your request for disability services. If you are a person with limited English and would like to request interpreter services, please contact ARB's Bilingual Manager at (916) 323-7053.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Sections Affected: Proposed adoption of new sections 95100 to 95133, title 17, California Code of Regulations (CCR), sections 95100 to 95133.

Background

In 2006 the legislature passed and the Governor Schwarzenegger signed the California Global Warming Solutions Act of 2006 (AB 32; Stats. 2006, chapter 488). In AB 32 the Legislature declared that global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The Legislature further declared that global warming will have detrimental effects on some of California's largest industries including agriculture and tourism, and will increase the strain on electricity supplies. While national and international actions are necessary to fully address the issue of global warming, the Legislature recognized that action taken by California to reduce emissions of greenhouse gases will have far-reaching effects by encouraging other states, the federal government, and other countries to act.

AB 32 creates a comprehensive, multi-year program to reduce GHG emissions in California, with the overall goal of restoring emissions to 1990 levels by the year 2020. AB 32 requires ARB to do many things, including:

- Adopting a list of discrete, early action measures by July 1, 2007 that can be implemented before January 1, 2010, and adopting such measures;
- Establishing a statewide GHG emissions cap for 2020, based on 1990 emissions, by January 1, 2008;
- Adopting a scoping plan by January 1, 2009 indicating how emission reductions will be achieved from significant GHG sources via regulations, market mechanisms and other actions;
- Adopting regulations by January 1, 2011 to achieve the maximum technologically feasible and cost-effective reductions in GHGs; and
- Adopting mandatory GHG emissions reporting regulations.

Mandatory GHG reporting regulations are an important component of AB32. This is because in order to reduce GHG emissions, it is first necessary to establish an effective program to estimate, report, and track these emissions. This in turn requires an accurate and verified source of facility-specific GHG emissions data. AB 32 thus requires that ARB: "... on or before January 1, 2008, ... adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program." (Health and Safety Code section 38530(a)).

Section 38530(a) further specifies, among other things, that these GHG reporting regulations must:

- require the monitoring and annual reporting of GHG emissions from GHG emission sources, beginning with the sources or categories of sources that contribute the most to statewide emissions;
- account for GHG emissions from all electricity consumed in the state, including transmission and distribution line losses from electricity generated within the state or imported from outside the state;
- incorporate the standards and protocols developed by the California Action Registry (where appropriate and to the maximum extent feasible), and make reasonable efforts to promote consistency among other existing and proposed international, federal, and state greenhouse gas emission reporting programs;
- ensure rigorous and consistent accounting of emissions;
- ensure that GHG emission sources maintain comprehensive records of all reported GHG emissions.

Description of the Proposed Regulatory Action

The purpose of the proposed regulation is to meet the requirements of AB 32 to develop a comprehensive, effective, and reasonable mandatory GHG reporting program for California. The primary objectives include: begin reporting with the most significant GHG emissions sources, use rigorous and consistent emission accounting methods and provide reporting tools, include verification of emissions data, and, to the extent feasible, provide consistency with the California Climate Action Registry (CCAR), except as needed to ensure complete and verifiable mandatory reporting.

The proposed GHG reporting regulation would require annual emissions reporting from facilities that account for approximately 94% of the total carbon dioxide (CO_2) produced in California from industrial and commercial stationary sources of emissions. Additional sources of GHG emissions will be accounted for through other mechanisms besides mandatory reporting, and are not included in this regulation.

Under the proposed regulation, the facilities required to annually report their GHG emissions would include electricity generating facilities, electricity retail providers, electricity marketers, oil refineries, hydrogen plants, cement plants, cogeneration facilities, and industrial sources that emit over 25,000 metric tonnes per year of CO_2 from stationary source combustion, including facilities such as food processing, glass container manufacture, oil and gas production, and mineral processing. The

staff proposal requires facilities to report their facility GHG emissions using the methods, equations, and emission factors specified in the regulation. To the extent feasible, these methods are consistent with existing CCAR protocols.

Staff is proposing that operators subject to reporting prepare and submit their GHG emissions estimates and other data as specified in the regulation. Greenhouse gas emissions reporting would be required from those with operational control of facilities or other entities subject to reporting. For this regulation, "operational control" for a facility means the authority to introduce and implement operating, environmental, health and safety policies. Nuclear, hydroelectric, wind, or solar electricity generating sources would not be required to report under the regulation. Hospitals with the North American Industry Classification System (NAICS) code starting with 62 would also not be required to report, nor would primary and secondary schools with a NAICS code of 611110. We have estimated that approximately 800 facilities would be subject to GHG reporting under the proposed regulation.

The proposed regulation provides specific reporting requirements for each industrial sector, defining which facility processes and greenhouse gases must be reported. In general, all facilities would be required to report their on-site stationary source combustion emissions of CO_2, N_2O (nitrous oxide), and CH_4 (methane). Some industrial sectors, such as cement and refineries, would also report their process emissions, which occur from chemical or other non-combustion activities. Facilities would report fugitive emissions as specified in the regulation. The CO_2 emissions from biomass-derived fuels would also be separately identified during reporting. In addition, the proposal would require that those reporting provide their consumption of purchased or acquired electricity and thermal energy, referred to in the regulation as indirect energy usage. An option is also provided in the regulation for the voluntary reporting of mobile source emissions within the context of an entity-wide California emissions report.

All data specified in the regulation would be reported to the ARB annually. The first emissions reports must be submitted in 2009 based on 2008 emission levels. To allow facilities to develop reporting systems, train personnel, collect data, and install any necessary equipment, a phase-in time is provided in which the reporting and verification requirements are less stringent for the first reporting year. Following this phase-in, those reporting must meet the more comprehensive reporting and verification requirements specified in the proposed regulation.

Except for the emissions reports submitted in 2009, submitted emissions and other data would undergo third-party verification to ensure the completeness and accuracy of the data, and to confirm the use of required methods in preparing the emission estimates. Under the proposal, the verification of facility emissions reports would be performed annually or triennially, depending on the complexity of the emission source. Either an air pollution control district/air quality management district or a private contractor could perform verification services, provided they met

specified education, experience, and training qualifications. Approval to perform verification services also involves a screening for conflict of interest by ARB.

Other items included in the proposed regulation and discussed in the ARB staff report are the detailed quantification and reporting requirements for each industrial sector, required elements of verification services, emissions verifier accreditation requirements, specifications for claiming confidential data, and document retention and record keeping requirements. Complete details are provided in the proposed regulation and staff report which are available here:
http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm

COMPARABLE FEDERAL REGULATIONS

Currently there are no federal statutes requiring comprehensive facility reporting of greenhouse gas emissions. However, the United States Environmental Protection Agency's Acid Rain Program requires the reporting of CO_2, SO_2, and NO_x emissions from certain fossil fueled power plants as part of its program to reduce atmospheric levels of sulfur dioxide and nitrogen oxides, which cause acid rain (see Title 40, Code of Federal Regulations, section 72.1.et seq.). Because of the very limited nature of this federal regulation related to GHG emissions reporting, the proposed ARB regulation is not duplicative of the federal requirements.

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

The ARB staff has prepared a staff report or Initial Statement of Reasons (ISOR) for the proposed regulation, which includes a summary of the economic and environmental impacts of the proposal. The ISOR is entitled: "Staff Report: Initial Statement of Reasons for Rulemaking: Mandatory Reporting of Greenhouse Gas Emissions Pursuant to the California Global Warming Solutions Act of 2006 (Assembly Bill 32)."

Copies of the ISOR and the full text of the proposed regulatory language may be accessed on the ARB's web site listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, 1st Floor, Sacramento, CA 95814, or by calling (916) 322-2990 within the 45 days prior to the scheduled hearing on December 6, 2007.

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 web site listed below.

Inquiries regarding the substance of the proposed regulatory action may be directed to the designated agency contact persons, Mr. Doug Thompson, Manager of the Climate Change Reporting Section, Planning and Technical Support Division at (916) 322-7062 or by e-mail at dthompso@arb.ca.gov, or Mr. Patrick Gaffney, Staff Air Pollution Specialist, at (916) 322-7303 or by e-mail at pgaffney@arb.ca.gov.

Further, the agency representative and designated back-up contact persons to whom nonsubstantive inquiries concerning the proposed administrative action may be directed are Ms. Alexa Malik, Manager, Board Administration & Regulatory Coordination Unit (916) 322-4011, or Ms. Amy Whiting, Regulations Coordinator, (916) 322-6533. The Board staff 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 available on the ARB Internet site for this rulemaking at: http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm

COSTS TO PUBLIC AGENCIES AND TO BUSINESSES AND PERSONS AFFECTED

The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies, private persons and businesses in reasonable compliance with the proposed regulatory action are presented below. A detailed assessment of the economic impacts of the proposed regulation is included in the Initial Statement of Reasons for this item.

The Executive Officer has made an initial determination that the proposed regulatory action will not have a significant statewide adverse economic impact directly affecting businesses, including the ability of California businesses to compete with businesses in other states, or on representative private persons. Because of the generally low reporting costs relative to typical facility revenues, the affected businesses should be able to absorb the costs of the proposed regulation with no significant adverse impacts on their profitability. We do not expect a noticeable change in employment, business creation, elimination or expansion, or business competitiveness in California due the reporting requirements.

In developing this regulatory proposal, ARB staff evaluated the potential economic impacts on representative private persons or businesses and determined that there will be a potential cost on private persons and businesses directly affected. Staff estimates that the total costs associated with meeting the greenhouse gas reporting requirements to be in the range of $10 to $50 million during the first and second years for businesses, local, and state government, with a midpoint estimate of approximately $30 million. Third year and subsequent costs are anticipated to be in the range of $6 to $35 million annually statewide, with a midpoint estimate of approximately $21 million. First and second year costs are higher due to the possible need for new equipment, sampling systems, training, and other start-up costs to meet the regulatory requirements. The ranges of the estimated costs are extremely wide because of the substantial variability in potential reporting and verification costs among facilities subject to the regulation. We anticipate costs to diminish over time as facilities incorporate GHG reporting into their normal business practices.

The specific cost for an individual facility subject to GHG reporting will generally depend on the complexity of the facility. Complex facilities with a large number of processes or which require ongoing monitoring of variable fuel streams, such as refineries, will have higher costs that could range from $50,000 to over $300,000 per year. Simple facilities such as those with only natural gas fired boilers can use default emission factors to estimate their GHG emissions, and their costs will likely be in the $3,000 to $20,000 per year range. Medium complexity facilities such as cement manufacturing plants or cogeneration plants would likely have annual reporting and verification costs in the range of $7,000 to $50,000. The vast majority of facilities and entities subject to reporting (over 90%) will fall within the low and medium complexity categories. Staff anticipates that the additional costs for reporting can be easily absorbed under existing operating expenses for most entities and facilities.

The Executive Officer has also determined, pursuant to title 1, CCR, section 4, that the proposed regulatory action will affect small businesses. Staff estimates that a maximum of 30-60 small business may be affected in California. We have attempted to minimize costs to these businesses by providing simplified emission estimation methods and less frequent verification for a majority of facilities anticipated to be small businesses. Based on the types of small business expected to be impacted and the kinds of GHG generating activities present at these facilities, the reporting and verification costs for a typical small business subject to the regulation should range from $3,000 to $15,000 per year.

Some public agencies could also be subject to GHG reporting, such as certain county or city owned sewage treatment works or landfills, various utility districts or publicly owned electricity providers, some State universities, and other State facilities that emit more than 25,000 metric tonnes of CO_2 from stationary combustion sources. The Department of Water Resources is also expected to have a reporting requirement related to imported power. These local and state government agency GHG reporting costs are anticipated to be less than $1 million per year statewide.

As described above, the proposed regulatory action will impose a mandate upon and create costs to some local agencies. Because the regulatory requirements apply equally to all reporting categories and unique requirements are not imposed on local agencies, the Executive Officer has determined that the proposed regulatory action imposes no costs on local agencies that are required to be reimbursed by the state pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code, and does not impose a mandate on local agencies that is required to be reimbursed pursuant to Section 6 of Article XIII B of the California Constitution.

An additional State cost will be incurred by the ARB to administer the reporting program. These costs include start-up costs to develop reporting tools and training materials, as well as annual costs for new staff to implement the reporting and verification program and maintain the reporting tool. Staff estimates that the initial ARB start-up costs will be roughly $600,000, with annual ARB operational costs of approximately $1 million to administer the program.

In accordance with Government Code section 11346.3, the Executive Officer has determined that the proposed regulatory action will not result in a loss of jobs within the State of California, or the elimination of existing businesses within the State. It is likely that the regulatory action will create the need for technical support for developing GHG emissions estimates, providing laboratory and other services, and providing emission verification services. It is anticipated that some of these services will be provided by existing companies and staffing; however, we anticipate that this regulatory action would result in some additional jobs within California to provide these services, and the expansion of some existing businesses. This regulatory action may also result in the creation of a few new businesses in California to provide these services.

Pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that the proposed regulatory action will not create costs or savings in federal funding to the state, or costs or mandate to any 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.

In accordance with Government Code sections 11346.3(c) and 11346.5(a)(11), the ARB's Executive Officer has found that the proposed GHG reporting requirements 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.

SUBMITTAL OF COMMENTS

The public may present comments relating to this matter orally or in writing at the hearing, and in writing or by e-mail before the hearing. To be considered by the Board, written submissions not physically submitted at the hearing must be received **no later than 12:00 noon, December 5, 2007**, and 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/listpub/comm/bclist.php

Facsimile submittal: (916) 322-3928

To ensure that your comment will be available for consideration it is important that your comment is received by the deadline.

Please note that under the California Public Records Act (Government Code section 6250 et. seq.), your written and oral comments, attachments, and associated contact information becomes part of the public record and can be released to the public upon request. This includes personal information provided with your comments, such as your home address, your home phone number, and your personal email address. Additionally, your comments, attachments, and associated contact information may become available via internet search engines.

The Board requests but does not require that 30 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 that authority granted to the ARB in sections 38510, 38530, 38580, 39600, 39601, and 41511 of the Health and Safety Code. This action is proposed to implement, interpret and make specific sections 38530, 38580, 39600, and 41511 of the Health and Safety Code.

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 section 11340) of the Government Code.

Following the public hearing, the Board may adopt the regulatory language as originally proposed or with nonsubstantial 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 the ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, 1st Floor, Sacramento, CA 95814, (916) 322-2990.

CALIFORNIA AIR RESOURCES BOARD

Tom Cackette
Acting Executive Officer

Date: October 9, 2007

STATE OF CALIFORNIA

California Environmental Protection Agency

AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING

PROPOSED REGULATION FOR

MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS
PURSUANT TO THE CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006
(ASSEMBLY BILL 32)

Planning and Technical Support Division
Emission Inventory Branch

October 19, 2007

STATE OF CALIFORNIA

California Environmental Protection Agency

AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING

PUBLIC HEARING TO CONSIDER

MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS PURSUANT TO THE CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006 (ASSEMBLY BILL 32)

Release Date: October 19, 2007
Scheduled for Consideration: December 6-7, 2007

This report has been prepared by the staff of the California Air Resources Board and approved for publication. Publication does not signify that the contents necessarily reflect the views and policies of the Air Resources Board.

STAFF REPORT: INITIAL STATEMENT OF REASONS

PUBLIC HEARING TO CONSIDER

MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS PURSUANT TO THE CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006

Air Resources Board Meeting
December 6, 2007 at 9:00 a.m.
Air Resources Board
Auditorium
9530 Telstar Avenue
El Monte, CA 91731

This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m. on December 6, 2007, and may continue to 9:00 a.m., December 7, 2007. Please consult the agenda for the meeting, which will be available at least ten days before December 6, 2007, to determine the day on which this item will be considered.

For those unable to attend the meeting in person, a live video webcast will be available beginning at 9:00 a.m. on December 6, 2007 at http://www.calepa.ca.gov/broadcast

This report and related materials are available for download from the Air Resources Board's Internet site at: http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm. In addition, written copies may be obtained from the Board's Public Information Office, 1001 I Street, 1st Floor, Environmental Services Center, Sacramento, California 95814, (916) 322-2990.

If you have a disability-related accommodation need, please go to: http://www.arb.ca.gov/html/ada/ada.htm for assistance or contact the ADA Coordinator at (916) 323-4916. If you are a person who needs assistance in a language other than English, please contact the Bilingual Coordinator at (916) 324-5049 or go to: http://inside.arb.ca.gov/as/eeo/languageaccess.htm.

Questions
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ATTACHMENT F: Text of the California Global Warming Solutions Act of 2006 (Assembly Bill 32)

EXECUTIVE SUMMARY

This report presents the California Air Resources Board (ARB) staff's proposed Mandatory Greenhouse Gas (GHG) Reporting Regulation pursuant to the California Global Warming Solutions Act of 2006 (the Act). The Act requires ARB to develop a regulation for the reporting of GHGs by January 1, 2008. This regulation was developed through an extensive public processes involving multiple stakeholders, State agencies, and the public.

Objectives of the Proposed Regulation

ARB staff has developed a regulation to meet the greenhouse gas reporting requirements specified in the Act, which include:

- begin reporting with the most significant GHG emissions sources;
- use rigorous and consistent emission accounting methods;
- provide for verification of reported emissions data;
- use the standards and protocols of the California Climate Action Registry (CCAR) to the extent feasible and appropriate.

The State is also working with other states to develop registries and reporting procedures that maximize consistency while preserving the rigor called for by the Act. California is actively participating in efforts to develop consistent reporting tools and procedures on a national and regional basis through The Climate Registry, a collaboration between states, tribes, and provinces, and the Western Climate Initiative.

Summary of Proposed Regulation

The proposed GHG reporting regulation requires emissions reporting from facilities that account for approximately 94 percent of the total carbon dioxide (CO_2) produced in California from industrial and commercial stationary sources. Additional sources of GHG emissions will be accounted for through other inventory mechanisms such as ARB's inventory model for motor vehicles, and are not included in this regulation. ARB staff has proposed that emissions reporting occur at the facility level, consistent with other mandatory programs. To support future program development, the regulation also would require reporting of entity identification information for the broader entities that own and operate the facilities that report. The ARB will provide electronic reporting tools to assist with mandatory reporting, and the tools will provide a mechanism for reporting additional voluntary entity-wide data for those who want to report this additional information.

Under the proposed regulation, the facilities required to annually report their GHG emissions include electricity generating facilities, electricity retail providers and power marketers, oil refineries, hydrogen plants, cement plants, cogeneration facilities, and industrial sources that emit over 25,000 metric tonnes per year of CO_2 from stationary source combustion. The latter category includes diverse facilities such as food processing, glass container manufacture, oil and gas production, and

mineral processing. The staff proposal requires facilities to report their facility GHG emissions using the methods and equations specified in the regulation. Staff has relied on CCAR protocols to craft the reporting methods for most sectors.

Basic Requirements and Gases. The proposed regulation provides detailed reporting specifications for each industrial sector, defining which facility processes and greenhouse gases must be reported. In general, all facilities report their on-site stationary source combustion emissions of carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4). Some industrial sectors, such as cement and refineries, would also report their process emissions of these same gases, which occur from chemical or other non-combustion activities. Facilities report fugitive emissions when specified in the regulation. The CO_2 emissions from biomass-derived fuels would be separately identified during reporting.

Particular requirements apply to the electric power sector to meet the requirements of the Act. Utilities and power marketers would be required to report certain electricity transactions, including purchases, sales, imports, exports, and exchanges. Emissions reports in the electric power sector will include two additional Kyoto gases, sulfur hexafluoride (SF_6) and hydrofluorocarbons (HFCs). Staff found no significant use of these compounds by the other sectors proposed for reporting. Also, for the sectors subject to reporting, we did not identify any significant use of perfluorocarbons (PFCs) so the proposed regulation does not explicitly require reporting of these substances.

The proposed regulation would also require that sources other than the electric power sector provide their consumption of purchased or acquired electricity and thermal energy, referred to as indirect energy usage.

The proposed regulation requires facilities subject to reporting to submit an emissions report annually to the ARB. The first emissions reports would cover 2008 calendar year emissions and be submitted in 2009. To provide a phase-in period for reporting 2008 emissions these estimates may be based on the best available information, incorporating the proposed ARB methods as feasible. All future emissions reports would need to fully comply with specified calculation requirements.

Verification of Emissions Reports. Except for the first-year reports, submitted emissions reports would be required to undergo third-party verification consistent with international standards to ensure the completeness and accuracy of the reported data. Under the proposal, verifications would be performed annually or triennially, depending on the complexity of the emission sources involved. The third-party verifiers, working in teams under the auspices of verification bodies (private firms or air districts), would be required to meet education, experience, and conflict of interest qualifications specified in the regulation prior to being approved by ARB to verify emissions reports. All verifiers would undergo pre-screening, ARB-approved training, and accreditation to perform verification services.

Implementation. Reporting would be implemented through an ARB approved web-based reporting tool. ARB will provide user-friendly interfaces, consistent with those being developed for The Climate Registry, to ease the reporting process. We will also publish guidance documents and conduct training over the next eighteen months, leading up to the first emissions reports in April 2009. We will work to streamline reporting requirements as much as possible for those already reporting to the California Energy Commission or other State agencies. To the extent that California air districts develop compatible tools to facilitate integrated GHG and criteria pollutant reporting, ARB would approve such optional tools for use by reporting facilities.

Coordination and Consistency with the California Climate Action Registry

The Act requires ARB to, "where appropriate and to the maximum extent feasible, incorporate the standards and protocols of the California Climate Action Registry" (CCAR) in the mandatory reporting program." ARB staff worked closely with CCAR staff throughout the rule development process. We looked to *standards* established by the CCAR program in setting core requirements, such as independent third-party verification. We looked to CCAR *protocols* as the foundation for our reporting methodologies, and as a result the requirements proposed bear strong similarity to CCAR requirements. This is particularly true for the cement, cogeneration, and general stationary combustion sources, as well as the verification element of the staff proposal. We also considered the requirements and reporting procedures under development to support The Climate Registry, and participated in initial discussion of reporting under the Western Climate Initiative.

Where differences between the ARB proposal and the CCAR program occur, they are due to (1) other requirements of the Act and California regulatory law; (2) the need to develop new methodologies for sources not specifically considered by CCAR protocols, and (3) agency recommendations and public comment. Examples of these differences are provided in this report.

Summary of Industry Sector Reporting Requirements

Staff is proposing that GHG emissions reports be required at the facility level for the sectors subject to reporting, and about 800 facilities are expected to be required to submit emissions data. A summary of the proposed requirements are included in Table 2. Electricity retail providers and marketers would have broader requirements that are often not facility-specific, such as reporting power purchases and sales. The company or organization with "operational control" over a facility -- the authority to introduce and implement operating, environmental, health and safety policies -- would be responsible for submitting the report each year. Backup generators and portable equipment at affected facilities would not be included in the reporting requirement. Hospitals and primary and secondary schools would be exempted from reporting.

Facilities would report their GHG emissions using methods specified by the proposed ARB regulation. The proposed ARB calculation methods are detailed and

well defined to help ensure consistency and accuracy in reporting. For simple or less significant GHG emission sources, the methods are based on look-up tables of emission factors. For larger, more complex or variable emission sources, calculations are based on methods specific to fuel type and process, and employ measurements of key parameters such as fuel heat value, carbon content, or direct measurement of GHGs through the use of continuous emission monitoring systems (CEMS). In some cases options are provided for the use of facility-specific test data to develop GHG emission factors.

Schedule Summary. Power generation and cogeneration facilities not part of other reporting entities, and industrial sources that emit over 25,000 metric tonnes of CO_2 per year from general stationary combustion sources, would report each year by April 1 on the previous year's emissions. Remaining facilities would report each year by June 1. Dividing reporters into two groups will help ensure sufficient availability of verifiers and facilitate ARB staff assistance with specific questions or problems. Each reporting deadline would be followed by a six-month period for verification of emissions reports, ending with verification opinions filed with ARB.

As mentioned above, facility operators reporting on their 2008 emission levels during 2009 may use the best available emissions data for their estimates. This ramp-up period will allow for the installation of monitoring equipment, development of record-keeping systems, and training of personnel. We will encourage use of the more accurate methods specified in the regulation so facilities can gain familiarity with the full requirements that will apply in subsequent years. Third-party verification of the 2008 emissions data would be optional.

Following are key reporting requirements by industrial sector:

Power Sector Overview:

During the development of mandatory reporting requirements for the electric power sector, three approaches were discussed as potential regulatory mechanisms to achieve emission reductions from the power sector. A source-based approach regulates electric generating facilities; a first-seller approach includes generating facilities and entities that import power into California; and a load-based approach regulates retail providers. Since the regulatory approach to be taken is an open question at this time, the reporting regulation requires information that would support any of these options. ARB will carry out an extensive public process prior to selection of a regulatory approach for this sector, and will receive formal recommendations from the California Energy Commissions and the Public Utilities Commission. These two agencies have recently provided joint formal recommendations for mandatory reporting in the electric power sector. ARB staff has incorporated these recommendations into the regulation and accompanying nonregulatory guidance. The sections below summarize the power sector reporting requirements.

Electricity Generating Facilities. Facilities with a total generating unit capacity of at least 1 megawatt (MW) that emit 2,500 metric tonnes or more of CO_2 would report

their CO_2, N_2O, and CH_4 emissions from fuel combustion. Where applicable they would also report CO_2 process emissions from acid gas scrubbers, fugitive CO_2 emissions from geothermal power, CH_4 emissions from coal storage, HFCs from generator cooling units, and SF_6 emissions from facility equipment. The facilities would report wholesale power exports when known. Fuel use data would also be reported.

Electricity Retail Providers. Retail providers would report the emissions above for the generating facilities they operate, and fugitive SF_6 emissions related to the transmission and distribution systems they maintain. Under the proposal retail providers would also report imported and exported power in megawatt hours, by source when known. There are additional requirements for retail providers related to implementing a possible load-based approach. These include reporting ownership share, renewable energy contract dates, determination of native load power, in-state power purchases and sales, out-of-state owned power sold to out-of-state entities, and other information. Attachment C of this document explains the staff proposal for performing calculations related to this sector.

Electric Power Marketers. Electric power marketers as defined under this proposal are power purchasing and selling companies or agencies that do not serve end users. They are required to report the amount of power they import into and export out of California. Marketers that maintain transmission system substations inside California would report fugitive SF_6 emissions at those substations as well.

Overviews of Other Sectors:

Cogeneration Facilities. Cogeneration facilities that meet the generating capacity (MW) and emissions thresholds of electric generating facilities, or that are operated by another reporting facility, would report CO_2, N_2O, and CH_4 emissions from fuel combustion at the facility, as well as the distribution of emissions for electricity generation, thermal energy production, and (when applicable) manufactured products. Process and fugitive emissions, where applicable, would be as specified for electricity generation units. Fuel use data would also be reported.

Petroleum Refineries. Refineries would report stationary combustion emissions of CO_2, CH_4, and N_2O using fuel specific emission factors that account for carbon variability; the methodology developed by ARB staff is an enhancement to existing protocols. Refinery process emissions reported would include CO_2 from catalytic cracking, CO_2 from hydrogen production, CO_2, CH_4, and N_2O from process vents, and CO_2 from sulfur recovery. Refineries would report certain fugitive emissions, including wastewater treatment CH_4 and N_2O emissions, CH_4 emissions from oil/water separators, CH_4 from storage tanks, and CH_4 from equipment fugitive emissions. If there is a cogeneration unit at refinery, the reporting requirements for a cogeneration facility apply. Fuel use data would also be reported.

Hydrogen Plants. Hydrogen plants emitting 25,000 metric tonnes or more of CO_2 would report their process-related CO_2 emissions from hydrogen production in addition to their CO_2, CH_4 and N_2O combustion emissions. If there is a cogeneration unit at the facility, then the cogeneration reporting requirements would also apply for the cogeneration unit. The plants would also report transferred CO_2, hydrogen production, and fuel use data.

General Stationary Combustion (GSC) Facilities. Facilities not included in the sectors above but emitting 25,000 metric tonnes or more of CO_2 per year from stationary combustion would report their CO_2, N_2O and CH_4 emissions from facility combustion sources. Most facilities can use simple default emission factors and fuel use data to estimate their emissions, but they have the option to use more detailed fuel analysis methods. Examples of some GSC facilities that could be required to report are shown in Table 1. If there is a cogeneration unit at a GSC facility, then all reporting requirements for a cogeneration facility would apply. Facility fuel use data would be reported. Because of their additional complexity and potential for significant fuel carbon content variability, GSC facilities that perform oil and gas production would implement specific fuel test requirements similar to refineries.

Table 1. Examples of Major Stationary Combustion Sectors Potentially Affected*

Natural gas transmission	Oil production
Industrial gases	Food processing
Paperboard manufacture	Steel foundries
Colleges and universities	Mineral processes
Glass container	Malt Beverages

*Note: Must also exceed 25,000 metric tonne CO_2 threshold to be subject to reporting.

In developing all requirements, ARB staff worked to apply the best scientific and technical information available. The data generated as a result of implementing the proposed regulation will inform decision processes critical to the success of the Act.

Future Updates to the Regulation

ARB staff will propose updates to this regulation in future years, to improve the current requirements and to add sectors as the overall California GHG program is further defined and calculation methods are adopted. We expect additional GHG emission sources in the oil and gas sector to be included in reporting once current protocol development work is completed. Other possible sectors for future reporting are discussed in this report, including the glass, chemical, and mineral processing industries. Staff will re-examine the thresholds for reporting in the general combustion sector and consider what industries have significant process emissions that should be reported. In addition, we anticipate that any facility that becomes part of a future GHG emissions trading program would become subject to annual verification requirements, if they are not already.

Table 2.

Summary of Proposed Mandatory Reporting Requirements

Topic/Sector		ARB Staff Proposal
Who Reports, What Level, How Often		♦ Facility-level reporting by company operating facility. ♦ Annual reporting of emissions by calendar year, beginning in 2009. ♦ Hospitals, primary and secondary schools, backup generators, portable equipment excluded. ♦ Non-regulatory option provided for voluntary reporting of entity emissions.
Reporting Scope and Source Categories		♦ Direct stationary combustion emissions. ♦ Specified process and fugitive emissions. ♦ Fuel usage by fuel type. ♦ Indirect energy usage--electricity in kWh and thermal in Btu. ♦ Mobile emissions in optional supplemental entity report.
Gases Reported		♦ Reporting of the six Kyoto gases is required as specified by sector. ♦ Most facilities will have only CO_2, CH_4 and N_2O to report. ♦ SF_6 and HFCs in the electricity sector. ♦ PFCs are not included in current proposal because it is not a significant GHG source for the sectors subject to reporting.
Emissions Quantification		♦ Sector-specific methods rely on fuel testing (heating value, carbon content) for combustion, or use of continuous measurement systems. ♦ Default emission factors provided for general stationary combustion sources; all sources can use default CH_4 and N_2O factors. ♦ Site-specific factors can be developed for some sources, under air district supervision with ARB approval.
Verification		♦ Required annually for more complex sources, triennially for less complex. ♦ Will be provided by third-party verifiers including air districts that meet accreditation criteria. ♦ Includes a conflict of interest policy. ♦ ARB will play an oversight role in verifications and quality of verifiers. ♦ Consistent with CCAR, TCR, ISO 14064-3, and EU practices.
Cement Plants		♦ Clinker-based method from CCAR for CO_2 process emissions with plant-specific factors. ♦ Combustion methods for CH_4 and N_2O use default emission factors. ♦ Fuel testing for CO_2 combustion factors, per CCAR.
Electricity Sector		♦ *Generating Units:* Report if $\geq$1 MW and $\geq$2,500 MT CO_2. ♦ Methods from CCAR power/utilities protocol include fuel testing or use of continuous monitoring systems; more frequent testing in some

Topic/Sector		ARB Staff Proposal
		cases to address fuel variability. ♦ Process and fugitive emissions methods from CCAR, including HFCs. ♦ Retail providers and power marketers also provide purchase, sales, import, export information per CPUC/CEC recommendations. ARB would apply default emission factors from CEC for unknown (and some known) power sources, and provisions to assure future reductions from contract changes are real. ♦ Facilities and entities report SF_6 fugitive emissions from equipment and circuit breakers.
Cogeneration Facilities		♦ Combustion methods like generating units (above). ♦ Distribution of emissions for electricity generation, thermal energy production, manufactured products based on CCAR Efficiency Method.
Petroleum Refineries		♦ Combustion methods for CO_2 use fuel specific emission factors derived from daily fuel sampling to account for carbon variability. ♦ Combustion methods for CH_4 and N_2O use default emission factors. ♦ Reported process emissions (CO_2,CH_4 and N_2O) include catalytic cracking, hydrogen production, process vents and sulfur recovery. ♦ Reported fugitive emissions (CH_4 and N_2O) include wastewater treatment, oil/water separators, storage tanks. ♦ CCAR discussion paper aided methodology development.
Hydrogen Plants		♦ Process-related CO_2 emissions from hydrogen production ♦ Combustion methods similar to refineries. ♦ Transferred CO_2 and hydrogen production.
General Stationary Combustion Facilities		♦ Facilities not included in other sectors but emitting 25,000 metric tonnes or more of CO_2 per year from stationary combustion would report their CO_2, N_2O and CH_4 emissions. ♦ Most facilities apply default emission factors and fuel use data to estimate their emissions, per CCAR protocols. ♦ GSC facilities involved in oil and gas production would implement specific fuel test requirements similar to refineries.

I. BACKGROUND AND INTRODUCTION

A. Structure of the Staff Report

This report with associated attachments represents the Initial Statement of Reasons (ISOR) 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 the mandatory reporting of greenhouse (GHG) emissions for California, how it was developed, why we selected the proposed options, and other information as outlined below.

The staff report is divided into the following sections:

- Section I. Background and Introduction – Discussion of regulatory requirements, the public process for developing the proposed regulation, and a general overview of the reporting requirements, including requirements for each industrial sector.
- Section II. Greenhouse Reporting Regulation Development – Discussion about many areas related to the regulatory development process such as coordination with others, the reporting schedule, emission factors, and reporting indirect energy use. Also included is information about reporting requirements and plans for the future.
- Section III. Sector Specific Reporting Requirements – Information about the reporting and emission calculation requirements for industry sectors subject to GHG reporting and how they were developed.
- Section IV. Verification – Discussion of the proposed verification requirements including how emission reports are to be verified, the procedure and qualifications for becoming a verifier, and the conflict of interest requirements for verifiers.
- Section V. Environmental Impacts of Regulation – Describes what impacts the proposed regulation may have on the environment, including a discussion of potential environmental justice impacts.
- Section VI. Economic Impacts of Regulation – Describes the economic impacts of the proposed regulation.
- Section VII. Alternatives to the Proposed Regulation – Describes other alternatives that were considered for the GHG reporting regulation and why the alternatives are less effective.
- Section VIII. References – Provides a list of references used for development of the staff report.
- Attachments A - F. Attachments include the proposed ARB regulation and its appendix of emissions factors and methods, and non-regulatory attachments including a regulation table of contents and matrix of estimation methods for sectors, Interim Emissions Attribution Methods for the Electricity Sector, the California Public Utilities decision and joint California Public Utilities Commission/California Energy Commission Proposed Electricity Sector

Greenhouse Gas Reporting and Verification Protocol, a technical attachment providing background and technical detail on the development of reporting requirements for oil refineries and hydrogen plants, and the text of the California Global Warming Solutions Act of 2006.

B. Background

Climate change poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. Global warming is projected to have detrimental effects on some of California's largest industries including agriculture and tourism, increase the strain on electricity supplies, and contribute to unhealthy air. National and international actions are necessary to fully address the issue of global warming. Action taken by California to reduce emissions of greenhouse gases will have important effects by encouraging other states, the federal government, and other countries to act. By exercising a leadership role, California will also position its economy, technology centers, academic and financial institutions, and businesses to benefit from national and international efforts to reduce emissions of greenhouse gases.

The legislature passed and the Governor signed the California Global Warming Solutions Act of 2006 (AB 32, Nunez, Statutes of 2006, chapter 488) to exercise this leadership role. Key provisions of the Act require ARB to determine a statewide greenhouse gas emissions level for 1990 and establish a 2020 emissions limit equal to that level, to identify greenhouse gas "early action" reductions, to develop a greenhouse gas emission reductions plan (the scoping plan) to achieve 1990 GHG levels, to adopt regulatory GHG emission reduction measures, and to adopt regulations to require the reporting and verification of greenhouse gas emissions.

A successful greenhouse gas reduction program requires a system to estimate, report, and track GHG emissions, to aid the identification and implementation of emission reduction strategies and monitor their effectiveness. Achieving the Act's objectives requires accurate, verified, facility-specific GHG emissions data based on standardized emission estimation methods. The Act therefore requires the ARB to "adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program" (Health and Safety Code (H&SC) section 38530(a)). In developing a GHG reporting regulation, the ARB must:

- Require annual GHG emissions reporting, beginning with the largest emission sources;
- Account for GHG emissions from all electricity consumed in the state, including imports and line losses;
- Strive for consistency with existing and proposed GHG emissions reporting programs, including the voluntary program of the California Climate Action Registry;

- Ensure rigorous and consistent emissions accounting, and provide reporting tools and formats that ensure necessary data collection;
- Maintain records of all reported emissions, and meet other requirements.

This proposed regulation for mandatory reporting of GHG emissions and the data collected will improve California's GHG emission inventory, provide a mechanism to track emissions trends, and support emission reduction strategies. The regulation is a central component of our efforts to quantify, evaluate, and reduce greenhouse gas emissions.

C. The Public Process in Rule Development and Implementation

ARB staff placed heavy emphasis on the public process in developing the regulatory proposal. In December 2006, staff held the first of five workshops to present initial ideas for mandatory reporting and collect comment on appropriate sources and approaches. Staff followed with a workshop in February 2007 to explain our rule development approach for the initial sectors proposed for mandatory reporting, including the formation of technical teams to focus on reporting methods and issues by sector. Workshop attendees and other interested parties signed up for teams on the electric power and utilities sector, the refineries sector, the cement sector, and general reporting.

Sector technical teams met twelve times throughout the spring and early summer to discuss calculation methods and potential reporting and verification requirements. Additional technical discussions were added on cogeneration and landfills, while the refineries discussions were broadened to include hydrogen plants and combustion from oil and gas production. ARB staff worked with air district emissions inventory staff to identify contact information for general combustion sources potentially subject to the regulation, and mailed notices of the May 23 workshop and a June 25 technical discussion to these sources.

Staff also met regularly with individual stakeholders to hear their concerns and recommendations. Staff shared concepts for the reporting regulation and gathered input from stakeholders through the technical discussions and the public workshops held May 23 and August 15, 2007.

A preliminary draft regulation was released for informal comment on August 10, 2007. Over 85 sets of comments by individual stakeholders were reviewed and considered as staff developed the proposed regulation for release October 19, 2007. A fifth workshop has been scheduled for October 31, 2007, to present and hear comments on the staff proposal, and staff will continue to meet with concerned stakeholders through the formal 45-day comment period leading up to the Board meeting in December.

Our public outreach process will continue after Board action through the implementation phase of the rule. In 2008, even as staff begins anew the rule development process for

the additional sectors being considered for mandatory reporting, we will write and release guidance documents to aid the reporting that begins in 2009. We will work with individual sectors and sources to identify implementation issues to address through guidance and training. Training will be offered upon release of the web-based reporting tool to be used for reporting. We will continue to work in close consultation with staff of the California Climate Action Registry and stakeholders as reporting nears, to draw on their experience and reduce duplication of effort where possible.

D. Proposed Regulation – A Summary

1. Objectives of the Proposed Regulation

The purpose of this regulation is to meet the requirements of the Act to develop a comprehensive and effective mandatory GHG reporting program for California. The Act requires the regulation to be adopted by January 1, 2008. Our primary objectives have included: starting with the most significant GHG emissions sources, using rigorous and consistent emission accounting methods, providing for the verification of reported data, and providing consistency with California Climate Action Registry (CCAR) standards and protocols, except as needed to ensure complete and verifiable mandatory reporting. ARB staff also has followed other state and regional efforts to develop reporting systems, and has proposed consistent approaches when possible.

2. Overview of Proposed Regulation

The proposed GHG reporting regulation includes annual emissions reporting from facilities that account for approximately 94 percent of the total carbon dioxide (CO_2) produced in California from industrial and commercial point sources. Additional sources of GHG emissions will continue to be accounted for through other mechanisms besides mandatory reporting; some of these will also be added to this regulation in future years as the greenhouse gas reduction program progresses. Potential future additions are discussed later in this report.

Under the proposed regulation, the facilities that are required to annually report their GHG emissions include electricity generating facilities, retail providers and marketers, oil refineries, hydrogen plants, cement plants, cogeneration facilities, and industrial sources that emit over 25,000 metric tonnes[1] per year of CO_2 from general stationary combustion (GSC) facilities, including facilities such as food processing, glass container manufacture, oil and gas production, and mineral processing. The staff proposal requires facilities[2] to report their emissions and

[1] A metric tonne is equal to 1.1023 short tons, or 2204.6 pounds, or 1000 kilograms.

[2] Note that in this report we will typically refer to "facilities" as the reporting entity. The regulation also includes reporting by electricity retail providers and marketers, which are not a single facility but carry out purchase, sales, distribution, and administrative operations.

other data using the methods, equations, and emission factors specified in the regulation.

Gases and Basic Requirements. The proposed regulation provides detailed reporting specifications for each industrial sector, defining which facility processes and greenhouse gases must be reported. In general, all facilities report their on-site stationary source combustion emissions of carbon dioxide (CO_2), nitrous oxide (N_2O), and CH_4 (methane). Some industrial sectors, such as cement and refineries, would also report their process emissions of these same gases, which occur from chemical or other non-combustion activities. Facilities report fugitive emissions when specified in the regulation. The CO_2 emissions from biomass-derived fuels would be separately identified during reporting.

Particular requirements apply to the electric power sector to meet the requirements of the Act. Utilities and power marketers would be required to report certain electricity transactions, including purchases, sales, imports, exports, and exchanges. Emissions reports in the electric power sector would include two additional Kyoto gases, sulfur hexafluoride (SF_6) and hydrofluorocarbons (HFCs), which are generally not found in the other sectors reporting.

In addition, the proposal would require that those reporting outside the electric power sector provide their consumption of purchased or acquired electricity and thermal energy, referred to as "indirect energy." Finally the ARB reporting tool will provide for the voluntary reporting of entity-wide emissions through a supplementary report.

Staff is proposing that facility operators report the GHG emissions specified in the regulation for each facility. The entity with "operational control" over the facility would be responsible for reporting the greenhouse gas emissions. For this regulation, operational control for a facility means the authority to introduce and implement operating, environmental, health and safety policies. Nuclear, hydroelectric, wind, or solar electricity generating sources would not be required to report under the regulation. Hospitals and medical facilities with the North American Industry Classification System (NAICS) code starting with 62 would also not be required to report, nor would primary and secondary schools with a NAICS code of 611110. We have estimated that about 800 facilities would be subject to GHG reporting under the proposed regulation.

Facilities would calculate GHG emissions using methods specified by the proposed ARB regulation. The proposed ARB methods are detailed and well defined to help ensure consistency and accuracy in reporting. For simpler GHG emission sources, the emission methods are based on look-up tables of emission factors. For more complex or variable emission sources, the methods are specific to fuel type and process, and employ measurements of key parameters such as fuel heat value, carbon content, or direct measurement of GHGs through the use of continuous

emission monitoring systems (CEMS). Limited options are also provided for use of facility-specific source data to develop GHG emission estimates.

Other items included in the proposed regulation are specifications for claiming confidential data, enforcement of the regulatory provisions, specific data to be reported to the ARB, and document retention and record keeping requirements.

Phase-in, Reporting, and Verification Schedule. The proposed regulation requires facilities subject to reporting to submit an emissions report annually to the ARB. The first emissions reports on 2008 GHG emissions levels would be submitted in 2009. ARB staff proposes a one-year phase-in period to allow facilities to develop reporting systems, train personnel in data collection and install any necessary equipment. To provide this phase-in period for reporting, emissions reported in 2009 may be based on the best available emission data, incorporating the proposed ARB methods as feasible. All future emissions reports would need to fully comply with specified calculation requirements.

Power generation and cogeneration facilities not part of other reporting facilities, as well as general stationary combustion (GSC) facilities outside the oil and gas sector, would report their emissions by April 1 each year. All other emissions reports would be due June 1 each year.

Verification of the first-year reports would be optional. Verification would be required for data reported on 2009 emissions levels (verification beginning in 2010) for all sources, except for general stationary combustion facilities, which would verify reported 2010 emissions levels (verification beginning in 2011). Verification would be required for each annual report submitted by retail providers, marketers, electricity generating and cogeneration facilities with capacities at least 10 MW, refineries, hydrogen plants, and general stationary combustion facilities in the oil and gas sector. Verification would be required at least triennially for cement plants, power plants under 10 MW or burning pure biomass fuels, and other general stationary combustion facilities. When required, verification would be due within six months of the emissions report submittal due date – October 1 or December 1.

Proposed reporting requirements for the industrial sectors included in the regulation are shown below. This is a basic summary only and is not exhaustive. Please refer to Section III below and the proposed regulatory language for additional detail.

3. Overview of Electricity Sector Reporting Requirements

During the development of mandatory reporting requirements for the electric power sector, three approaches were discussed as potential regulatory mechanisms to achieve emission reductions from the power sector. A source-based approach regulates electric generating facilities; a first-seller approach includes generating facilities and entities that import power into California; and a load-based approach regulates retail providers. Since the regulatory approach to be taken is an open question at this time, the reporting regulation requires information that would

support any of these options. ARB will carry out an extensive public process prior to selection of a regulatory approach for this sector, and will receive formal recommendations from the California Energy Commissions and the Public Utilities Commission. These two agencies have recently provided joint formal recommendations for mandatory reporting in the electric power sector. ARB staff has incorporated these recommendations into the regulation and accompanying nonregulatory attachment. Separate requirements would apply to generating facilities, retail providers and marketers as summarized below.

Electricity Generating Facilities. Facilities with a total generating unit capacity of at least 1 megawatt (MW) that emit 2,500 metric tonnes or more of CO_2 would report their CO_2, N_2O, and CH_4 emissions from fuel combustion. Where applicable they would also report CO_2 process emissions from acid gas scrubbers, fugitive CO_2 emissions from geothermal power, CH_4 emissions from coal storage, HFCs from generator cooling units, and SF_6 emissions from facility equipment. The facilities would report wholesale power exports when known. Fuel use data would also be reported.

Electricity Retail Providers. Retail providers would report the emissions above for the generating facilities they operate, and fugitive SF_6 emissions related to the transmission and distribution systems they maintain. Under the proposal retail providers would also report imported and exported power in megawatt hours, by source when known. There are additional requirements for retail providers related to implementing a possible load-based approach. These include reporting ownership share, renewable energy contract dates, determination of native load power, in-state power purchases and sales, out-of-state owned power sold to out-of-state entities, and other information.

Electric Power Marketers. Electric power marketers as defined under this proposal are power purchasing and selling companies or agencies that do not serve end users. They are required to report the amount of power they import into and export out of California. Marketers that maintain transmission system substations inside California would report fugitive SF_6 emissions at those substations as well.

4. Overview of Reporting Requirements for Other Sectors

Cogeneration Facilities. Cogeneration facilities that meet the generating capacity (MW) and emissions thresholds of electric generating facilities, or that are operated by another reporting facility, would report CO_2, N_2O, and CH_4 emissions from fuel combustion at the facility, as well as the distribution of emissions for electricity generation, thermal energy production, and (when applicable) manufactured products. Process and fugitive emissions, where applicable, would be as specified for electricity generation units. Fuel use data would also be reported.

Petroleum Refineries. Refineries would report stationary combustion emissions of CO_2, CH_4, and N_2O using fuel specific emission factors that account for carbon variability; the methodology developed by ARB staff is an enhancement to existing protocols. Refinery process emissions reported would include CO_2 from catalytic

cracking, CO_2 from hydrogen production, CO_2, CH_4, and N_2O from process vents, and CO_2 from sulfur recovery. Refineries would report certain fugitive emissions, including wastewater treatment CH_4 and N_2O emissions, CH_4 emissions from oil/water separators, CH_4 from storage tanks, and CH_4 from equipment fugitive emissions. If there is a cogeneration unit at refinery, the reporting requirements for a cogeneration facility apply. Fuel use data would also be reported.

Hydrogen Plants. Hydrogen plants emitting 25,000 metric tonnes or more of CO_2 would report their process-related CO_2 emissions from hydrogen production in addition to their CO_2, CH_4 and N_2O combustion emissions. If there is a cogeneration unit at the facility, then the cogeneration reporting requirements would also apply for the cogeneration unit. The plants would also report transferred CO_2, hydrogen production, and fuel use data.

General Stationary Combustion (GSC) Facilities. Facilities not included in the sectors above but emitting 25,000 metric tonnes or more of CO_2 per year from stationary combustion would report their CO_2, N_2O and CH_4 emissions from facility combustion sources. Except for oil and gas facilities with fuels having potentially high variable carbon content, most facilities can use simple default emission factors and fuel use data to estimate their emissions, but they have the option to use more detailed fuel analysis methods if greater accuracy is desired. If there is a cogeneration unit at a GSC facility, then all reporting requirements for a cogeneration facility would apply. Facility fuel use data would be reported. Because of their additional complexity and potential for significant fuel carbon content variability, GSC facilities that perform oil and gas production would implement specific fuel test requirements similar to refineries.

Another provision of the proposed regulation permits a general stationary combustion facility to cease emissions reports in the event a change in operations causes a decline in CO_2 emissions to below 20,000 metric tonnes for three consecutive years, as reflected in the submitted emissions reports. Such facilities would be required to resume reporting if emissions return to 25,000 metric tonnes. (A similar provision is included for power plants.) A third-party verifier would act to verify the reduction and the expectation of its permanence in the third year.

5. Overview of Verification

A key element of a credible GHG emissions reporting program is independent verification of the reported emissions to ensure the completeness and accuracy of the emissions estimates and conformance to the regulation. Under the proposed regulation, verification would be performed by qualified and trained third-party verifiers that meet specifications for education and experience, and demonstrate that there is no conflict of interest for verifying the emissions report data due to current or previous relationships with the facility operator. Verifiers would be required to attend a multi-day ARB approved verifier training course and successfully complete an exit exam prior to being accredited to provide verification services for California's mandatory GHG reporting program.

A private firm accredited by ARB to carry out verification would be required to have at least 2 lead verifiers on staff, and a minimum of 5 staff. California Air Pollution Control Districts or Air Quality Management Districts providing verification services would be required to meet the experience and training requirements specified in the proposal, but they have slightly different business qualification requirements because they are government agencies. A lead verifier would be accredited through an ARB training and exam process and meet specific background and experience qualifications.

Elements of verification as proposed in the regulation include (1) site visits during the first year of verification to ensure that all required emission sources and processes within the defined facility boundaries are included in the emissions estimates and that the emissions report is complete, (2) development of a plan for specific verification activities, including site visits and document reviews, (3) development of a sampling plan to conduct data checks on the reported emissions, that considers source contributions with the highest emissions and greatest uncertainty, and (4) a verification opinion submitted to ARB and the reporting facility. These and other elements of verification services are discussed in detail in Section IV of this report.

II. GREENHOUSE GAS REPORTING REGULATION DEVELOPMENT

This section includes a discussion of some of the key topics and issues ARB staff encountered while developing the GHG reporting regulation, including topics relevant to all of the industry sectors subject to reporting, and how we resolved them. Section III, which follows, provides detailed information specific to each industry sector such as cement plants and refineries.

A. General GHG Reporting Topics and Issues

1. Selection of Sources for First Year Reporting

ARB staff considered several key criteria in the selection of the first sectors and sources for mandatory reporting. The size of the emissions inventory for a particular sector and facilities within that sector was the first criterion, given the Act's direction to begin with the largest sources. The need for emissions information relative to the quality of the emissions inventory, and for early monitoring of scoping plan and regulatory progress, were key factors. The existence of California Climate Action Registry protocols as a foundation for specifying emissions estimation methodologies was another important consideration. The Act's specific requirements related to the power sector and electricity retail providers had to be addressed. The desire for a level playing field within the petroleum refining sector led to the inclusion of hydrogen plants in first-year requirements.

The staff proposal represents an initial set of reporting requirements. As required by the Act, this regulation will be periodically reviewed and updated. Reporting requirements will be refined for the sectors already included, and new sectors will be added. Additional sources under consideration for mandatory reporting are discussed at the end of this section of the staff report.

2. Coordination and Consistency with the California Climate Action Registry

The California Global Warming Solutions Act requires ARB to, "where appropriate and to the maximum extent feasible, incorporate the standards and protocols of the California Climate Action Registry" (CCAR) in the mandatory reporting program. The Act further requires that "entities that voluntarily participated in the California Climate Action Registry prior to December 31, 2006, and have developed a greenhouse gas reporting program, shall not be required to significantly alter their reporting or verification program except as necessary to ensure that reporting is complete and verifiable for the purposes of compliance with this division as determined by the state board."

ARB staff worked closely with CCAR staff to develop the mandatory reporting requirements. CCAR staff members were active and very helpful participants in our workshops and technical discussions, offering their experience and perspective on the important elements of a GHG reporting program. ARB staff looked to *standards*

established by the CCAR program in setting core requirements; independent third-party verification is an important example. Staff looked to CCAR *protocols* as the foundation for our reporting methodologies, and as a result the requirements proposed here bear strong similarity to CCAR requirements. This is particularly true for the cement, cogeneration, and general stationary combustion sources, as well as the verification element of this proposal.

There are some differences between proposed ARB and current CCAR requirements. Where these differences occur, the reasons are related to (1) other requirements of the Act and California law; (2) the need to develop new methodologies for sources not specifically considered by CCAR protocols, and (3) anticipated program needs and public comment. Examples follow:

- The Act requires ARB to begin with the largest sources of emissions; this requires facility-specific reporting, consistent with other mandatory reporting programs. CCAR requires entity-wide reporting with optional facility reporting. Our emphasis on specific sources and processes obviated the need to require reporting of mobile source emissions at facilities, which are extremely small for those subject to the proposed regulation. The ARB reporting tool will provide an option for a voluntary supplemental report of entity-wide emissions if desired.
- The Act requires reporting to be *complete* and verifiable, with *rigorous* and *consistent* accounting of emissions (emphasis added). In interpreting the Administrative Procedure Act (APA), the Office of Administrative Law (OAL) has for many years imposed strict requirements on test methods and calculation procedures specified in State regulations. As a result of both sets of requirements, the staff proposal is generally more definitive than CCAR protocols, and provides fewer options for emissions accounting. ARB's proposed regulation would also require the reporting of more GHGs sooner, and require the reporting of *de minimis* sources with simplified accounting.
- ARB staff thought it important to address petroleum refineries and hydrogen plants in our first-year reporting requirements. As CCAR had not yet developed a protocol for these sources, ARB staff developed a number of new methodologies for the regulation, with the aid of a CCAR discussion paper. For refineries and oil-and-gas production sources the potential for highly variable carbon content in fuels necessitates rigorous test regimes beyond CCAR general combustion protocols.
- The Act requires accounting for GHGs from all power consumed in the state, including imports and line losses. This required development of new methods and rule language tied to electricity purchases and sales. We relied on recommendations from the California Public Utilities Commission and the California Energy Commission in formulating these methods, which are beyond CCAR requirements.
- ARB staff places high priority on the public process, and public comments may have resulted in other minor deviations from CCAR protocols where ARB staff thought such requests reasonable and appropriate.

Finally it should be mentioned that the CCAR program itself is not a static program. Registry staff has adapted and are adapting CCAR requirements to the dynamic nature of GHG reporting. Additional changes are contemplated in response to the formation of The Climate Registry, as well as the adopted ARB regulation. ARB will continue to work closely with CCAR staff, and monitor development of other state and regional reporting frameworks so that reporting programs become as robust and consistent as possible.

3. Reporting and Verification Schedules

Throughout the rule development process staff heard concerns about the need to prepare for reporting, the desire to avoid multiple or duplicative reporting, and the expressed need for sufficient time to complete verification services. The staff proposal attempts to address all of these concerns.

The proposed reporting schedule requires affected facilities to submit annual GHG emissions reports to the ARB beginning in 2009. The initial 2009 submittal would report on 2008 emissions levels, but could rely on best available information to calculate emissions. A full year is provided to train staff, install equipment, and develop measurement regimes, as discussed in the next subsection of this report.

Staff have proposed two separate due dates for emissions reports by sector, but have avoided multiple dates where facilities or entities cross sectors. Electric generating facilities and cogeneration facilities that are *not* part of other reporting entities, along with general stationary combustion (GSC) facilities outside the oil and gas sector, would submit emissions reports each year by April 1, for emissions occurring in the previous calendar year. All remaining reports would be due by June 1. The two reporting dates will allow help ensure adequate availability of technical and verifier support services.

Verification would be optional for the first reports. Verification requirements would begin in 2010 for most sources, and in 2011 for general stationary combustion facilities. Six months are permitted for verification when it is required. Facilities that submit their emissions reports April 1 have until October 1 to have their emissions verified and receive a verification opinion. Facilities that submit emissions reports June 1 have until December 1 to complete the verification process.

All facilities report annually, but verification is permitted on a triennial basis for certain small or less complex sources.[3] Facilities in this category include cement plants and electricity generation or cogeneration facilities with generating capacities <10 MW or combusting pure biomass-derived fuels, as well as general stationary combustion facilities outside the oil and gas sector. Power facilities rated under 10 MW are permitted a triennial verification option because of their relatively small emissions (likely below 25,000 metric tonnes) and straightforward calculation methods. Biomass facilities were given the option for triennial verification because their emissions are

[3] It is expected that any facility that is included in a future market-based emissions trading program would be subject to verification of emissions reports at least annually.

generally considered "carbon neutral." Cement plants are afforded the triennial verification option because of relatively stable emissions and straightforward quantification, but would be required to complete additional verification following a significant facility change as specified in the proposed regulation.

Staff expect that the staggered reporting and verification deadlines and the phase-in and limitations on verification requirements, along with our commitment to work hard in the coming eighteen months to prepare for reporting and verification, will ensure both ARB and the network of verifiers will be ready to implement the regulation's requirements.

4. Preparation and First-year Reporting

Stakeholder comments expressed a broad concern about the quick implementation schedule proposed in the draft regulation that was circulated August 10, 2007. In order for reports of 2008 emissions to be filed in 2009 using prescribed methods, they pointed out, affected operators would need to begin almost immediately after Board action to collect, analyze and retain data. There would not be sufficient time to train personnel, develop data keeping systems, and in some cases, order and install equipment. Stakeholders have recommended phase-in or practice periods of from eight months to three years before reporting would be subject to compliance action.

There are several reasons why staff believes it important to gather information on 2008 emissions beginning in 2009. The Act requires ARB to adopt a mandatory GHG reporting regulation by January 1, 2008. The proposed December 2007 Board action meets that requirement, and staff does not want to unnecessarily delay reporting given the keen interest in early action and the need for emissions data for development of emission reduction strategies. Reporting of 2008 data in 2009 will provide important initial information on facility-specific GHG emissions levels, assist facilities in gaining familiarity with the GHG reporting and verification process, and provide needed information for program development.

However, staff recognizes the need for time for reporting facilities to make structural or data collection system changes, and the consequent need for some flexibility in getting reporting started. The proposed regulation would permit emissions reports filed in 2009 to be based on *best available* estimates of 2008 emissions, rather than on the exact methods specified in the regulation by source and fuel type. Best available is defined to include generally accepted alternative methods for calculating GHG emissions. Staff intends that what constitutes best available will be a matter of professional judgment for the operator given the particular circumstances of the affected facility and available records. Often data will be more "solid" for months later in 2008 when data collection systems have been put in place. Entities already reporting to CCAR may also be better prepared to report using prescribed methods.

Emissions reports for 2008 would still be required in 2009, though verification would be optional. Staff believes that one year should be sufficient time to install data collection systems, train personnel and fully prepare for use of the more definitive methods

specified in the regulation, and we expect emissions reports filed in 2010 to reflect full implementation of prescribed methods.

5. Defining a "Facility" and an "Operator"

A key consideration for facility-based reporting is what constitutes a facility. Staff have relied to some extent on traditional definitions that include stationary sources and equipment "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...". This definition is written to describe a facility in the traditional industrial sense such as a factory, a power plant, and other sources that have well defined footprints.

Some of the entities subject to the proposed regulation are not specific facilities. Retail providers may operate some facilities, but have been designated as also responsible for reporting power purchase and sales information on an entity basis. For this reason the regulation relies on the term "operator" to designate the party responsible for submitting an emissions data report. An operator may be in operational control of a facility (i.e., have authority to implement operating, environmental, health and safety policies within the facility's physical boundaries), or an operator may be the company or organization such as a retail provider or marketer that is involved in electricity transactions subject to reporting. Facilities don't report – operators report -- for a facility with GHG sources, for a set of transactions resulting from GHG emitting activities, or both.

Another exception to the traditional facility definition is military bases. Some military bases are spread over many thousands of acres and encompass a wide variety of activities such as employee housing, medical facilities, airfield operations, aircraft repair, ship construction and repair, and other operations. Each of these operations could also be under the operational control of different branches of the military, or military contractors within the confines of a base. ARB staff has thus provided the option for a military base to subdivide the base for reporting purposes into independent functional groupings, based on the types of operations performed on the bases. Through this mechanism, each base would not necessarily have to report as a single facility, but could subdivide based on "operational control" (defined in the regulation), and on major functional groupings such as aircraft repair and overhaul, or ship construction and repair operations. As with traditional "facilities," only those GHG sources specified within the proposed regulation would be reported, while unspecified sources such as residential heating and cooling would not be included.

6. De Minimis Emission Sources

The California Climate Action Registry General Reporting Protocol permits up to 5 percent of entity emissions to be excluded from reporting as *de minimis.* Preliminary thinking on emissions protocols for The Climate Registry (TCR) suggest adoption of a 3 percent *de minimis* level that may be excluded from emissions reports. The European Union Monitoring and Reporting Guidelines permit facilities to designate a portion of

their "minor source streams"[4] that together emit the larger of 1,000 metric tonnes or 2 percent (up to 20,000 MT) of total fossil fuel CO_2 emissions as *de minimis* sources. Under EU requirements *de minimis* emissions are still reported, but alternative "no-tier" emissions calculation methods of the operator's choosing may be used in place of prescribed methods for these sources (EU 2007).

The staff proposal would limit emissions claimed as *de minimis* to specific sources chosen by the operator that represent no more than 3 percent of total facility emissions, not to exceed 10,000 metric tonnes of CO_2 equivalent emissions. Emissions would still be estimated and reported for the selected de minimis sources, but alternative emission estimation methods could be used.

Because the Act requires emissions reports to be complete and rigorous, ARB staff has not proposed to permit exclusion of specified sources from reporting. Staff has specified sources by sector that are common and potentially significant for the sector, and has excluded sources not tied to facility processes and not likely to be significant.

Nonetheless, ARB staff recognizes that the cost of tracking emissions for every small source using the regulation's specified methods can be excessive, and that facilities may be in a position to use sound alternative methods to estimate emissions from these sources. The regulatory proposal thus allows for sources specified by the operator as *de minimis* to be calculated using alternative methods chosen by the operator. Such *de minimis* emissions would still be reported to assure the completeness of the emissions report consistent with the Act, and the chosen estimation methods would remain subject to the verifier's oversight and professional judgment as to their reasonableness, to avoid a material undercounting of emissions.

7. Efficiency Metrics for GHG Reporting

Efficiency metrics offer a method to measure and report greenhouse gas emissions on a per unit basis. Some commenters have recommended that the regulation include efficiency metrics for each sector, suggesting that reporting this information would be beneficial to ARB as a measure to identify relative facility efficiencies and opportunities for emission reductions.

The final proposal includes two efficiency metrics in the reporting requirements for cement plants. One efficiency metric calculates CO_2 emissions per metric tonne of cementitious product. This efficiency metric was adapted from the Registry's Cement Reporting Protocol. The second efficiency metric measures CO_2 emissions per metric tonne of clinker manufactured on-site. This efficiency metric was included to ensure

[4] Under the EU Guidelines "minor source streams" are source streams selected by the operator that jointly emit 5,000 metric tonnes of fossil CO_2 or less per year or contribute less than 10 percent (up to a total maximum contribution of 100,000 metric tonnes of fossil CO_2 per year) to the total annual emissions of fossil CO_2 before subtraction of transferred CO_2, whichever is the highest in terms of absolute emissions.

that cement plants only producing clinker would be compared equally to all other cement plants.

For facilities and other reporting entities in the electric power sector, the ARB regulatory proposal does not specify efficiency metrics. The regulation does, however, require reporting of the information needed to calculate several possible efficiency metrics for electric generating facilities, retail providers, and power marketers. With this data the ARB (or facility operators) can calculate such metrics should they be needed in the future, once specific regulatory requirements for the sector are decided. The CCAR Power and Utilities Protocol (PUP) requires entities and electric generating facilities participating in the voluntary reporting program to report three efficiency metrics, quantifying CO_2/MWh for electricity generated based on: 1) total energy electricity generation, 2) fossil fuel electricity generation, and 3) total electricity deliveries.

The current regulatory proposal does not require efficiency metrics for the remaining industry sectors subject to reporting. Staff reviewed the CCAR General Reporting Protocol, which discusses efficiency metrics as part of optional reporting and determined that the metrics for the remaining sectors are not sufficiently developed to include them in a mandatory GHG reporting program. Regulatory direction is key to specification of efficiency metrics, and it is generally too soon to establish efficiency metrics in advance of scoping plan development and establishment of regulatory targets by sector. However, as regulatory direction becomes clearer and methods and data become available, staff will evaluate the inclusion of efficiency metrics for additional reporting sectors in future revisions of the regulation. Because efficiency metrics allow reporters to track performance over time and can provide a uniform standard of comparison between facilities regardless of size, they can be very helpful in understanding and evaluating facility GHG emission levels relative to regulatory requirements.

8. Using Facility Source Test Data to Derive Emission Factors

Several stakeholders commented on the lack of suitability of current default emission factors for their facilities. In particular, changes in operating parameters and use of exhaust treatment devices as required by State or local rules can significantly impact levels of N_2O and CH_4 from combustion devices. The staff proposal thus permits facility operators to apply ARB-approved emission factors derived from source tests conducted under the supervision of ARB or the air district in emissions calculations for these gases. On approval of a source test methodology, factors would be updated in future years.

If desired, entities combusting municipal solid waste or biomass may request that ARB also certify a source-specific CO_2 emission factor for each facility. Similarly, fugitive CO_2 emissions from geothermal facilities may be evaluated on a source-specific basis. A provision allowing the development of a system specific emission factor (in lieu of the ARB default emission factor) has also been included in the methodology for the calculation of process CO_2 emissions from sulfur recovery units at refineries.

Until approval of each source-specific factor is obtained from ARB, default emission factors would still be required for mandatory reporting. But ARB staff agrees that source-specific information will generally be superior to default emission factors when available, and we hope to make use of the expertise of local air districts to assist with review and approval of source test methods and derived emission factors.

9. Reporting Indirect Energy Usage

At workshops and in written comments, some stakeholders have questioned the need to collect energy usage information in emissions reports. Such information would be reported in kilowatt-hours (kWh) for electricity received and British thermal units (Btu) for heat, cooling or steam.

Reporting of indirect emissions is a requirement of the California Climate Action Registry's reporting program, and ARB staff has considered extensively the value of indirect emissions in a mandatory reporting program. The staff proposal does not require an emissions calculation, but seeks energy usage and provider information that would enable ARB to estimate indirect emissions, along with indication whether the operator is paying a premium to purchase "green power" from utility-specified renewable sources. If calculated, indirect emissions would be estimated and assigned by source in an entirely separate accounting regime to avoid any double-counting.

Our principal consideration is that indirect energy usage provides a more complete picture of the emissions footprint of the facility. As facilities consider changes that would affect their emissions – addition of a cogeneration unit to boost overall efficiency even as it increases direct emissions, for example – the relative impact on total (direct plus indirect) emissions by the facility level should be monitored. Annually reported indirect energy usage also aids the conservation awareness of the facility and provides information to ARB as we consider future strategies by industrial sector. For these reasons we have included the requirement in the staff proposal.

10. Voluntary Entity-Wide Reporting

A fundamental difference between the proposed mandatory reporting program and California's current voluntary program is the emphasis in the staff proposal on facility-level emissions. The Act directed ARB to begin with the largest emission sources and categories of sources. Staff believes this requires a facility-specific (rather than company-level) approach – consistent with other mandatory reporting programs and necessary to provide an appropriate resolution of data for tracking progress under the ARB regulatory program. Staff nonetheless recognizes there may be companies who have been reporting to the California Climate Action Registry on an entity basis compiled from individual facility reports. For facilities subject to mandatory reporting, the ARB reporting tools will allow for voluntary reporting of entity-wide emissions through an optional supplemental entity report that, when taken with the required facility reports, may provide a company-wide scope of emissions in California. The goal of this approach is to enable those providing information voluntary to programs, such as CCAR, to voluntarily submit additional entity information to the ARB.

11. Mobile Sources

The California Climate Action Registry requires the reporting of mobile source emissions by companies and organizations filing emissions reports. Mobile source emissions are not necessarily tied to particular facilities, since by their nature vehicles commonly move offsite, and nonroad equipment may be portable and located onsite only temporarily. Staff investigated the types of vehicles and equipment in use at the sector-specific facilities subject to this regulation. We found that emissions from mobile sources at affected facilities generally represent well under 1 percent of facility emissions. In the context of a cement plant, power plant, hydrogen plant or refinery, mobile emissions are very small -- a small fraction of the proposed regulation's reporting threshold for general stationary combustion sources.

For this reason reporting of mobile source emissions is voluntary rather than required in this first mandatory reporting regulation. Mobile sources often become more significant when fleets and transportation are represented at the entity level, however, as reflected in some of the emissions reports filed with CCAR. In addition, staff recognizes that additional reductions in the transportation sector will be needed to meet the goals of the Act, and we plan reassess this issue as the program develops. Staff has included mobile source methods consistent with CCAR in the current proposal for use in supplemental entity-wide emissions reports or voluntary reporting at the facility level.

12. Backup Generators, Intermittent Use and Portable Equipment

Under the proposal, GHG reporting would be required by facilities that have a stationary electric generating capacity of 1 megawatt (MW) or more and emit 2,500 metric tonnes or more of CO_2 from this equipment during the calendar year subject to reporting. Facilities subject to this requirement would report using the applicable methods defined for electric generating facilities in Section 95111. In addition, the regulatory proposal also specifically excludes stationary generators classified as backup generators in air pollution control district permits.

These changes from our earlier proposals are based on comments received that expressed concerns about whole facilities being brought into reporting solely because of having a number of small generators which, when combined, exceeded 1 MW, or because of backup generators that were rarely used, but nevertheless exceeded the 1 MW capacity threshold. We set the threshold at 2,500 tonnes CO_2 because this is roughly the amount of CO_2 produced by a 1 MW generator running full time for a year. It is it is important for us to collect GHG emissions from any generating sources larger than this so we can adequately quantify California's energy load distribution and GHG emissions.

In addition to backup generators, portable generators or pumps and other non-stationary or portable sources are not subject to reporting in this initial staff proposal. In most cases, the emissions from this equipment will be negligible compared to the process or direct combustion emissions at the facility. Future GHG reporting regulations may require this additional reporting, but for this first phase, the main focus is on direct combustion and process emissions from high emitting stationary sources.

13. Additional Issues Raised in Regulation Development

Consistency with 1990 Emissions Inventory Methods. Separate provisions of the Act require ARB to determine statewide GHG emissions in 1990 and to approve an equivalent 2020 emissions limit. A number of stakeholders have urged that the methods chosen for mandatory reporting be consistent with those used to generate the 1990 emissions inventory and 2020 limit.

This is not feasible because the reporting regulation must focus on reporting methods to be applied at a facility level while the current statewide inventory methods must rely on aggregate inventory data sources by sector. Over time, as we collect facility specific ("bottom up") inventory data we plan to use this information as a check on the aggregate statewide "top-down" sector-based inventory. However, different approaches will likely continue to be used because the top-down statewide inventory is a broad based look at relative contributions of various sectors and total statewide emissions. Lastly, establishment of an aggregate 2020 statewide emissions limit based on the 1990 level does not confer an obligation on any particular source or sector to return to its 1990 level of emissions. Nor do any source or sector estimates for 1990 represent a 2020 limit on that source or sector.

Sufficient Availability of Verifiers. A concern raised by stakeholders is whether there will be a sufficient pool of verifiers, both in general and for sector specific purposes. Staff has proposed minimum requirements for verification bodies, lead verifiers, and verifiers to establish a high quality verification program, yet those criteria are flexible enough to allow several mechanisms by which an individual can demonstrate the qualification to take ARB verifier training and become a verifier. Even if a company doesn't meet the minimum requirements to be a verification body, its staff can take verifier training and be subcontractors to another firm until the company is able to qualify as a verification body. Individuals can also take training and become part of a verification team under the auspices of other bodies.

Staff has tried to directly address concerns that there might not be enough verifiers to meet the demands of all facilities subject to reporting, by providing for staggered reporting and extended verification periods. The proposed reporting and verification deadlines are designed to prevent the concentration of verification services to a short annual season, which is important given the number of emissions reports required. Staff has already begun preparation for the verification program. ARB expects to offer multiple verifier training and accreditation opportunities before the first verifications begin in 2009. We have established goals to qualify 75 lead verifiers, 50 sector-specific verifiers, and 150 verifiers overall by early 2009. We will also encourage reporting entities to establish verification arrangements early enough to ensure compliance with the deadlines of the regulation. These steps will help assure high emissions data quality and contribute to a smooth verification process.

Landfill GHG Emissions Reporting. ARB staff gave strong consideration to inclusion of solid waste landfills in first-year reporting requirements. Several dozen landfills will be

reporting combustion emissions from power generation or flaring because they meet the applicable thresholds. But California has over 200 landfills with sufficient methane generation to have gas collection systems in place, and ARB estimates that fugitive emissions of methane from landfills represents 1 to 2 percent of the statewide GHG inventory. The California Integrated Waste Management Board has pointed to data gaps in current models, and is working with the California Energy Commission on a three-year research project to help better understand methane formation and movement at California landfills. ARB staff is serving on the advisory panel to this study, which should improve the tools available to estimate landfill methane emissions. Staff consulted the principal investigator, who indicated that detail on waste-in-place and cover area by cover type would help with model estimation when the study is complete in 2010. In addition, ARB emissions inventory staff would like to routinely collect specific information on gas capture and control systems.

ARB has adopted methane capture from landfills as a discrete early action item, and a control measure is under development for adoption in 2008. ARB staff has decided to defer landfill information reporting requirements to further consideration in the development of the landfills early action measure, to avoid duplication of requirements and provide more time to consider what data are needed. For these reasons the current staff proposal does not require reporting by landfills, except when the landfill operator has operational control of electric generating facilities and general combustion sources using landfill gas. Landfill operators with electricity generators rated 1 MW or higher and emitting at least 2,500 metric tonnes per year of CO_2 would be required to report emissions according to the methods prescribed in section 95111. Operators with flaring or other combustion emissions exceeding 25,000 metric tonnes per year of CO_2 would report under the general combustion requirements specified in section 95115. Any landfills with cogeneration facilities would be subject to the separate requirements specified in section 95112.

Enforcement. The goal of the GHG reporting regulation is to collect complete and accurate GHG emissions data from facilities subject to reporting. We intend to work hard and closely with affected facilities to assist them in complying with the regulation. This will include providing guidance documents, training, workshops, on-line reporting tools, and having staff readily available to answer questions. We are committed to making the program effective for both the affected facilities and the ARB through outreach and compliance assistance efforts.

Several stakeholders expressed concern about non-definitive or vague language in the August 10 preliminary draft regulation, such as requirements for an "effective" GHG accounting system, coupled with potentially far-reaching enforcement provisions. We have attempted to craft the proposal with attention to definitive language and the enforcement provisions that add clarity to ARB intentions.

The enforcement provisions of the proposed regulation are contained in section 95107. They are designed to clarify the number of days of violations that would occur if required reports and information are not submitted to ARB by the deadlines specified in the

regulation, or if false information is knowingly submitted with intent to deceive. These provisions implement and make specific Health and Safety Code section 38580(b)(3), which authorizes ARB to develop a method to convert regulatory violations into the number of days of violation for the purposes of the penalty provisions specified in section 42400 et seq. of the Health and Safety Code. It should be emphasized, however, that ARB's fundamental goal is to collect accurate GHG emissions data, not to collect penalties. We will work closely with those subject to reporting and our third-party verifiers to assure that we can meet this goal.

B. GHG Data Reporting Submittals and Recordkeeping

1. Reporting Mechanism

An early implementation step for ARB staff is development of a reporting mechanism. In deciding this mechanism staff has looked to existing programs, most notably CCAR's voluntary GHG reporting program. CCAR provides an online reporting tool called CARROT, but is moving toward a new national tool under the auspices of The Climate Registry (TCR). ARB intends to provide a comparable and consistent online reporting tool to the TCR tool for mandatory GHG reporting in California.

The online tool will be developed to meet the reporting requirements of the regulation and will provide a user friendly interface to guide reporting entities through screens pertinent to their sector reporting needs. ARB plans to have a beta test period in 2008 in which stakeholders will have a chance to use and comment on the tool. Staff will also hold training classes and provide guidance on how to use the tool to submit data.

ARB received comment from sources already reporting data to other State and federal government agencies, particularly in the electric power sector, requesting that reporting requirements be combined. ARB staff is committed to working with the California Energy Commission, in particular, to examine the feasibility of a single reporting platform that would serve the needs and requirements of both agencies. Staff is also working with California air districts to facilitate integrated reporting processes where possible.

2. Contents of GHG Emissions Reports

The proposed regulation provides detailed information about what must be included in greenhouse gas emission reports and the data used to develop these reports. This information is separated into two tiers. The first tier is the specific data that must be submitted to the ARB through the appropriate reporting mechanisms. This includes general information such as facility name and address, specific information such as fuel use, fuel type, process and unit information where applicable, and of course facility emissions and other data as specified by sector.

The second tier of information described in the regulation is the detailed underlying data used by facilities to generate their submitted GHG emission reports. This might include fuel test data, continuous emissions monitoring data, device specific information, and

other data. This data is to be maintained by the facility and used by verifiers to evaluate the completeness and accuracy of the submitted emission reports. In addition, the ARB has the authority to obtain this underlying information as needed to evaluate compliance with the regulatory requirements.

Finally, facility operators are required under the regulation to maintain data and systems to ensure that GHG emission data are complete, transparent, and accurate, and to provide internal audits and quality assurance of the submitted emission reports.

3. Release of Reported Emissions Data

The main objective of the mandatory GHG reporting program is to provide complete, detailed, and accurate facility-specific GHG emissions data. ARB staff's intention is to provide quality emissions data to the public as quickly as practical, but with with recognition that verification is an important step in the process. We expect to provide annual facility-level emissions reports and various summary reports based on the submitted data. In most cases, these reports would include only verified data, but release of unverified data may be necessary, particularly for facilities that are only subject to triennial verification in order to provide complete summary information for a calendar year. Unverified data would be flagged as unverified. Reported GHG emissions data will be available through ARB websites beginning in 2010, following verification of the 2009 emissions reports.

4. Designation of Confidential Information

Stakeholders subject to reporting have expressed concern for the protection of commercially sensitive data, while community organizations have urged a high level of transparency for the data used to calculate emissions. ARB must balance these competing needs. As indicated in the proposed regulation, ARB will handle sensitive information and claims of confidentiality by following the procedures specified in ARB's confidentiality regulations, which are contained in title 17, California Code of Regulations, sections 91000 to 91022. These regulations allow companies who submit information to ARB to claim such information as confidential. The regulations also specify a process for ARB's handling of such information. ARB staff has many years of experience handling confidential information and takes its responsibilities very seriously. All information that is designated as confidential will be handled in strict accordance with ARB confidentiality regulations.

The proposed regulation requires facility operators or retail providers to report both emissions data and non-emissions data. As part of the reporting process, facility operators and retail providers will have the opportunity to designate parts of the submitted data as confidential. There are some limits on what can be claimed as confidential by the reporting entity. The California Public Records Act (Government Code section 6250 et seq.) provides that all air pollution emissions data are public records (see Government Code section 6254.7(e)). Accordingly, the proposed regulation specifies that emissions data, including estimates of facility emissions, are public information and cannot be claimed as confidential. For non-emissions data that have been claimed as confidential by the operator, members of the public can use the

procedures specified in ARB confidentiality regulations (cited above) to request access. ARB staff would then notify the affected facilities or entities to provide justification for the claims of confidentiality, consistent with the procedures specified in the regulations.

C. Adding Sources to Mandatory Reporting

The Act requires ARB to begin mandatory reporting "with the sources or categories of sources that contribute the most to statewide emissions." The reporting program proposed by staff for Board consideration in December 2007 would result in reporting of about 40 percent of total California GHGs beginning in 2009. Another 40 percent of GHG emissions are from the transportation sector, and these emissions are accounted for through other inventory mechanisms. As the regulatory program progresses additional requirements are likely to be added.

The California Climate Action Registry (CCAR) is developing a reporting protocol for natural gas transmission and distribution. CCAR is also working with the Western Regional Air Partnership to establish a framework for development of a reporting protocol for upstream sources in the oil and gas sector for the western states. ARB is supportive of these efforts and would like to begin with the protocols that emerge from these processes to establish calculation methods and reporting requirements for mandatory reporting in California. The "holes to fill" in our proposed requirements would include process, fugitive, and some combustion emissions from exploration, production, transmission, and distribution in the oil and gas sector.

While several stakeholders have indicated that the threshold of 25,000 metric tonnes CO_2 in the staff proposal is an appropriate place to draw the line for reporting of stationary combustion emissions, others have asked ARB to consider a lower threshold, so that additional emissions from smaller sources would be reported. Implementation of the proposed regulation will account for about 94 percent of industrial and commercial point source emissions in California. Staff will examine options for reporting of additional combustion emissions in the future. These options may include reporting of "downstream" emissions by fuel providers (e.g., gas companies), or reporting by the smaller sources themselves.

There are also process and fugitive emissions to be considered for sources of combustion emissions that have already been drawn in with this proposal. ARB staff intends to look more closely at process and fugitive emissions in the industrial sectors that will begin reporting in 2009, for significance that would warrant the addition of process and fugitive emissions in subsequent reporting years. The glass manufacturing, chemical, and mineral processing industries are examples of industries with process emissions that probably fit this category.

The largest overall category of GHG emissions in California, the transportation sector, has not been addressed by the current reporting proposal. There are some practical reasons for this. One is the question of an appropriate mechanism for mobile source

reporting, since as individual sources cars, trucks, and offroad vehicles are too small and numerous to make reporting practical. In recognition of the need to achiev additional reductions in the transportation sector if the goals of the Act are to be met, staff plans to examine reporting options for this sector in the future.

In addition, Governor Schwarzenegger's Executive Order S-20-06 requires ARB, in coordination with the Secretary for Environmental Protection, to work with the California Climate Action Registry to develop reporting and reduction protocols for local governments and agriculture. Staff will consider the role of these and other sources in mandatory reporting within the context of scoping plan needs as that plan moves forward in the coming year, and again following its adoption.

III. SECTOR SPECIFIC REPORTING REQUIREMENTS

This section provides chapters that describe the reporting requirements specific to each sector subject to the GHG reporting regulations and how they were developed.

A. Cement Manufacturing Plants

1. Background

Cement production generated about 6 million metric tonnes of process-related CO_2 emissions in 2004. A similar amount of GHG emissions are also emitted into the atmosphere each year from the combustion of fuels to heat the kilns where limestone manufactured into clinker. As the largest consumers of coal in California, cement plants emit GHG emissions from coal combustion and fugitive methane emissions from coal storage. Staff has proposed inclusion of cement manufacturing plants in mandatory reporting due to their contribution to the statewide GHG inventory (approximately 2 percent of the total), their importance as a contributor to emissions worldwide, and access to CCAR and other cement reporting protocols as a foundation for development of calculation methods.

Beginning in January 2007 staff formed a Cement Technical Team, with key stakeholders including the Portland Cement Association (PCA), U.S. EPA Climate Leaders, California-based and national cement companies, air quality management districts with cement plants in their jurisdiction, the California Energy Commission (CEC), the California Department of Transportation (Caltrans), and non-governmental associations including the Natural Resources Defense Council (NRDC), World Business Council for Sustainable Development (WBCSD) and World Resources Institute (WRI). The team met three times for technical discussions, at which staff presented several methods to estimate GHG emissions from cement manufacturing, and received stakeholder comments. Additional discussions were held directly with interested stakeholders.

Staff presented the results of technical discussions in the May 23, 2007 public workshop, and preliminary regulatory concepts during the August 15, 2007 public workshop. Stakeholders provided further comments in late August and early September. Staff also received suggested changes from local air districts during a conference call on September 13, 2007. Taking into consideration this broad variety of stakeholder input, staff prepared the final regulatory proposal.

2. Basis for Proposal

Staff reviewed GHG emissions reporting guidance documents developed by CCAR (CCAR 2005), U.S. EPA Climate Leaders (USEPA 2003), the WBCSD Cement Sustainability Initiative (WBCSD 2005), the Intergovernmental Panel for Climate Change (IPCC) (IPCC 2006c), the European Union (EU), the United Kingdom (UK) (DEFRA 2003), Japan (Japan 2006), and the U.S. Department of Energy (U.S. DOE)

(USDOE 2007). We evaluated the GHG reporting requirements and methodologies adopted by each program. Each reporting program includes methodologies to quantify GHG emissions from the manufacturing process, stationary fuel combustion, mobile source combustion, fugitive emissions, and indirect emissions from electricity usage. Staff presented methodologies for reporting requirements for each of these sources to stakeholders during cement technical team meetings. The final proposal includes requirements for cement plants to report all these emissions except indirect and mobile combustion emissions, as discussed below.

Among existing GHG reporting programs, the CCAR, U.S. EPA Climate Leaders, WBCSD Cement Sustainability Initiative (CSI) and IPCC 2006 protocols all recommend a clinker-based approach to estimate CO_2 emissions from cement manufacturing. Staff presented the IPCC 2006 Clinker-Based method in comparison with the Registry/CSI Clinker-Based methods to stakeholders during the April 11, 2007 Cement Technical Team meeting. Both equations include the quantity of clinker produced and a clinker emission factor. The IPCC 2006 equation multiplies these variables by a CKD correction factor. The Registry/CSI equation multiplies these variables and adds the amount of CKD generated multiplied by a CKD emission factor. The calculation to determine the correction factor for CKD in the IPCC 2006 method includes more variables than the Registry/CSI equation to determine the emission factor for CKD. As a result the Registry/CSI equation may result in fewer errors.

CO_2 emissions estimates yield the same results in both equations with the exception of situations where cement plants discard cement kiln dust (CKD). Staff concluded the variation in emissions results was based on differences in assumed CKD calcination rates. The Registry/CSI approach assumes that 100 percent of the CKD is calcined and the IPCC 2006 equation assumes a 50 percent CKD calcination rate. If both equations assume the same CKD calcination rate, the equations would yield nearly the same emissions results. Some cement plants use the Registry/CSI method to report GHG emissions to U.S. DOE. Since stakeholders are more familiar with the equations and the calculations may result in fewer errors, they recommended ARB adoption of the Registry/CSI clinker-based method.

ARB staff evaluated two other methodologies to estimate process-related CO_2 emissions from clinker production: the cement-based and the kiln input based methods. The cement-based method uses the total volume of cement produced to estimate the clinker content and CO_2 emissions associated with clinker production. The kiln input based method estimates CO_2 emissions based on the carbonate content of raw materials input into the kiln.

According to IPCC 2006, the cement-based method is a Tier 1 Method that is not consistent with good practice because it estimates clinker production based on cement production data. The kiln input based method (use of carbonate(s) input data) is a Tier 3 Method, the highest tier resulting in the most accurate emissions results. This method in IPCC 2006 relies on plant-specific data to estimate emissions based on the CO_2 content of the carbonate raw materials. It was determined that this method may

overestimate emissions if the carbonates in the raw materials are not fully calcined. Staff has recommended the clinker-based approach for the final regulation; it is a Tier 2 Method that is consistent with good practice. This method was also supported by the Cement Technical Team.

Staff evaluated the significance of mobile source emissions at cement plants and other facilities proposed for reporting. Mobile combustion CO_2 emissions from on-site mobile quarry equipment and off-road quarry vehicles at a typical plant were estimated to total 3000 to 4000 metric tonnes, or about 0.3 percent of the plant total. This estimate excludes indirect emissions from fleets and railcars used to transport cement from the plant to ready-mix concrete plants. Mobile source emissions are not included in the final staff proposal for cement plants, but may be considered again as staff considers mobile source reporting options in the future.

3. Reporting Requirements and Methods

Under the staff proposal, all eleven cement plants manufacturing cement in California would be required to report process-related CO_2 emissions from clinker production using the Registry/CSI clinker-based method. They would also report process-related emissions from the organic carbon entrained in non-carbonate raw materials. Cement plants would also be required to report annual CO_2, N_2O, and CH_4 emissions from fuel combustion. Direct on-site combustion emissions are measured by fuel type using plant-specific data or emission factors as specified in Section 95110, using the methods in Section 95125, Additional Calculation Methods. Direct fugitive methane emissions from coal storage would be reported following the calculations also specified in the Additional Calculation Methods section of the regulation. Cement plants would also report the amount of indirect energy usage in kilowatt hours or Btus, as well as energy provider information. Finally we are proposing that cement plants would report two efficiency metrics. One efficiency metric is based on CO_2 emissions per ton of cementious product. The other efficiency metric is based on annual CO_2 emissions per ton of clinker manufactured.

The Registry/CSI clinker-based method calculates CO_2 emissions based on the volume and composition of clinker produced as well as the amount of CKD discarded during the manufacturing process. The cement regulation requires cement plants to calculate plant-specific clinker and CKD emission factors. The clinker emission factor is based on the percent of lime and magnesium oxide content of the clinker. The CKD emission factor must be calculated only when cement plant operators do not recycle CKD back to the kiln. There are at least two cement plants in California that discard CKD; these facility operators would also calculate a plant-specific CKD calcination rate.

For reasons of inventory completeness, cement plants would be required to report process-related emissions from the total organic carbon content in raw materials. This was an optional reporting requirement under the Registry protocol. After consultation with stakeholders, staff included this calculation as an additional requirement. It is especially relevant for cement plants that consume large amounts of shale or fly ash

and generate CKD, which may result in a higher percent of total organic carbon content in the raw materials entering the kiln.

The final proposal would require cement plants to calculate fuel combustion emissions based on the quantity and type of fuel burned annually. Cement plants estimate stationary fuel combustion emissions using measured high heat value and carbon content depending on fuel type. Emissions from alternative fuels would be estimated using measured heat content, measured carbon content, or with plant-specific emission factors measured from source tests approved by local air districts and/or ARB.

As an option, cement plant operators may determine CO_2 emissions using continuous emission monitoring systems (CEMS). This option would replace the methods to calculate process-related and fuel combustion CO_2 emissions. CEMS would need to be installed and operated according the requirements of 40 CFR Part 60 or 40 CFR Part 75 To allow ARB to continue to separately estimate combustion emissions, the staff proposal requires cement plant operators to report fuel usage information by fuel type whether or not CEMS are employed.

Coal is the main fuel used to manufacture cement. Under the staff proposal fugitive methane emissions from coal storage would be reported using default emission factors. Some stakeholders expressed concerns that fugitive methane emissions are minimal, and should not be included in mandatory reporting. Depending on the source of the coal, methane emissions could vary from around 200 to over 2,500 metric tonnes. Staff have chosen to include this requirement to aid inventory development and because these emissions are tied to facility processes. Under the regulation's proposed *de minimis* requirements, emissions within this range could be estimated using alternative methods selected by the operator, but would still be reported and verified.

In addition to reporting total carbon dioxide, methane, and nitrous oxide emissions, cement plant operators are required to report CO_2 emissions per metric tonne of cementitious product. The efficiency metric is based on direct CO_2 emissions from the manufacturing process and stationary combustion. It is the same as the efficiency metric included in the CCAR Cement Reporting Protocol, except that it does not include indirect emissions in the numerator. The cementitious product in the denominator of the equation includes all clinker manufactured on-site and all materials used to manufacture cement. ARB received recommendations to include a second efficiency metric that would include just clinker in the denominator to account for CO_2 emissions per ton of clinker manufactured. Staff included this second efficiency metric in the final proposal to ensure an equitable comparison of clinker production facilities.

The final staff proposal follows the policy direction of the Act by adopting the Registry protocols whenever possible. Staff recommends the clinker-based approach for estimating CO_2 process emissions because it meets the definitions of good practice. The proposal also incorporates a more accurate representation of cement plant GHG emissions by requiring the calculation of plant-specific emission factors. The requirements for estimating organic carbon in raw materials, fuel combustion emissions

and fugitive methane emissions are all included in the Registry's Cement Reporting Protocol as sources to quantify a complete inventory of cement plant GHG emissions.

B. Electric Power Sector: Electric Generating Facilities, Retail Providers and Power Marketers

1. Background

The electric power sector produces greenhouse gases (GHG) in three ways: from operating large combustion facilities that burn fossil fuels, from transmitting and distributing electric power, and from handling and storing fuels. This sector emitted roughly 124 MMT of CO_2 equivalent (CO_2e) emissions in calendar year 2004, representing roughly one quarter of total GHG emissions in ARB's Draft California GHG inventory as of August 22, 2007 (CARB 2007a). More than half of emissions from this sector are associated with imported electrical power generated largely from coal-fired power plants. In addition to CO_2 emissions, the electric power industry uses 80 percent of all sulfur hexafluoride (SF_6) produced worldwide. Circuit breaker applications account for most emissions of SF_6, which has a global warming potential 23,900 times that of CO_2 (IPCC 1996).

The Act requires reporting for major sources of GHG emissions and emissions from all electricity consumed in the state, including transmission and distribution line losses. Thus, mandatory reporting must, at a minimum, address emissions associated with in-state generation and imported power needed to meet retail needs.

CPUC and CEC Parallel Process. Prior to passage of the Act, the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) had already begun implementation of programs to increase efficiencies and reduce greenhouse gases. For the past several years the CPUC has been developing mechanisms to encourage utilities to invest in renewable energy sources. In a February 2006 decision, the CPUC adopted the concept of a load-based GHG emissions cap as a unifying framework for utility procurement incentives. Phase 1 of this decision implemented an emissions performance standard (EPS) for long term contracts that is based on combined cycle natural gas power generation. The EPS was adopted to keep long term investments in line with renewable energy goals while the CPUC took time to design and implement a load-based cap program. Setting an EPS also met SB 1368 mandates that directed both the CPUC and CEC to adopt an EPS.

Phase 2 is the forum for implementing the load-based GHG emissions cap. It was to begin in September 2006, but when the Act was signed that same month, the CPUC delayed starting Phase 2 to coordinate with ARB. The CPUC issued the scoping for Phase 2 in February 2007 and put forth a schedule for investigating issues and for providing ARB with recommendations for mandatory reporting of GHGs and for implementing a load-based cap program. In order to coordinate their efforts, the CPUC and the CEC are jointly participating in the Phase 2 proceedings.

In September 2007, the CPUC and the CEC finalized their recommendations to the ARB on mandatory reporting of GHGs. The ARB has taken these recommendations and integrated them into ARB's GHG mandatory reporting regulation.

Regulation Development Process. Since February 2007, ARB has met with more than thirty stakeholders individually. ARB staff held three technical discussions specifically for this sector on April 10, May 8, and June 21, 2007. The technical discussions were in addition to the general workshops conducted by ARB for all sectors covered in the proposed regulation. There were roughly 40 participants on average at each of technical discussions. Stakeholders provided substantial comments on the first draft concept proposed by ARB in early June, and on the August 10 draft proposed regulatory language.

ARB staff maintained close coordination with staff of the CPUC and CEC throughout the development of ARB's proposed regulation and their recommendations to ARB. One of the challenging issues addressed through the CPUC/CEC public process was how to determine emissions from purchases made from unspecified sources of power generation both in California and imported from out-of-state. The CPUC and the CEC held several joint workshops during their public process. Workshops were held in April 2007 on reporting and tracking of GHG for a load-based cap, in June 2007 on the 1990 electric sector baseline, and in August 2007 on point of regulation where load-based and first seller approaches were discussed. The CPUC, CEC, and ARB mutually participated in the technical discussions and workshops put on by the three agencies throughout the course of the past year.

The California Climate Action Registry (CCAR) participated in these events as well. In addition to participating in ARB workshops and technical discussions, CCAR staff provided technical assistance to the ARB staff during the development of the proposed regulation. The CCAR's Power and Utilities Protocol for voluntarily reporting GHG emissions at the entity level provides methodologies that serve as the cornerstone for ARB's proposed regulation. The protocol is consistent with other programs and protocols worldwide, and protocol methodologies are included in ARB's proposed regulation to the fullest extent possible.

Other Protocols Considered. In addition to CCAR's protocol methodologies, staff consulted reporting protocols and methodologies from around the world including the Monitoring and Reporting Guidelines of the Commission of the European Communities (EU 2007), the United Kingdom Emissions Trading System (Defra 2003), the New South Wales Greenhouse Gas Abatement Scheme, the Regional Greenhouse Gas Initiative (RGGI 2007), IPCC Guidelines (IPCC 2006a), the International Organization for Standardization (ISO 2006), World Resources Institute (WRI/WBCSSD 2001), U.S. EPA Climate Leaders Greenhouse Gas Inventory Protocol (EPA 2005), U.S. DOE Technical Guidelines for Voluntary Reporting of Greenhouse Gases (1605(b)) Program (DOE 2007), and U.S. EPA Acid Rain regulation and protocols.

ARB staff has selected methodologies from references that represent a level of accuracy by fuel type generally recommended for emissions trading programs. In addition to the CCAR protocol, the proposed regulation relies in particular on U.S. EPA technical guidance developed for the Acid Rain Program.

Relationship to Future Regulations. The nature of a future regulatory program is an open question. Potention approaches under discussion are referred to by names that indicate the point of regulation within the sector: "source-based," "first-seller," or "load-based." Under a source-based cap, regulators allocate responsibility for emissions to the direct sources of these emissions. In the electricity sector the major sources of emissions are the electrical generating facilities. The first-seller approach is a modification of the source-based approach which accounts for emissions associated with electricity imports by placing responsibility for these imported emissions on the entity that initially sells the power into California. Under a load-based system, the retail providers are held responsible for all emissions generated to produce the electricity used to serve their customers' load.

In June of 2007 the Market Advisory Committee released its recommendations for design of a greenhouse gas cap-and-trade scheme, advocating a first-seller point of regulation for the electricity sector. The CPUC and the CEC are scheduled to provide joint recommendations on future trading regulations in early 2008.

Information needed to support future regulatory approaches varies depending on what approach is taken. The information collected from the electricity sector under the mandatory reporting system has been designed to provide a sufficient foundation for any of the three regulatory schemes described above.

2. Basis for Proposal

Reporting Threshold. The Act mandates that ARB account for emissions from all electricity consumed in the state. ARB staff interprets this mandate to include not only power sold retail to California consumers by retail providers but also power produced on the premises of a particular retail customer and dedicated to serving that customer. As a result, the proposed reporting threshold for electric generating facilities of $\geq$1 megawatt (MW) and $\geq$ 2,500 tonnes of CO_2 per year from generating activities applies to all generating facilities, including self-generation facilities. The threshold encompasses virtually all power generated in California, representing about 99 percent of megawatt hours (MWh) generated. Portable and emergency backup generators that operate intermittently during the year and are designated as such in a local air pollution control agency permit are excluded from reporting requirements.

The $\geq$1 MW threshold aligns with reporting to the CEC, where information from the power sector is used to produce the CEC's "Quarterly Fuels and Energy Reports." ARB is committed to working with the CEC to develop reporting tools that will streamline reporting to both agencies.

The threshold includes hybrid generating facilities (i.e., partially powered with one or more fuels that emits GHGs) but excludes generating facilities that are solely nuclear, hydroelectric, wind, or solar powered since these facilities are thought to emit virtually no GHGs. It will be necessary to account for electricity transactions from these facilities.

Reporting Entities. The proposed regulation would require operators of generating facilities, retail providers, and electric power marketers to report to ARB annually. This combination enables ARB to collect information on generation and imports needed to account for all power consumed in California and to support any of the three regulatory approaches.

The term, "retail providers," is defined in the proposed regulation to mean any entity that provides electricity to end users in California. Retail providers include investor owned utilities, publicly owned utilities, multi-jurisdictional utilities, electric service providers, Community Choice Aggregators, and the Western Area Power Administration, an agency of the U.S. Department of Energy, and the California Department of Water Resources.

Electric power marketers are defined as purchasing/selling entities that are not retail providers (i.e., do not provide power to end users) but are listed as the purchasing/selling entity at the "first point of delivery" for power imported into California or the "last point of receipt" for power exported from California.

There is inherent overlap in reporting by operators of generating facilities and by retail providers or marketers; however, the need to have operators report is three-fold. First, it provides necessary data to improve ARB's GHG emissions inventory and conduct technical analysis, including self-generation not reported by retail providers. Secondly, it enables ARB to develop a by-facility dataset of emissions that insures consistency when assigning emissions associated with power purchases. Finally it prepares California to participate in a source-based trading program should one be adopted.

The proposed regulation also invites operators of generating facilities outside California that import power into the state to voluntarily report their GHG emissions. This can be advantageous to an out-of-state facility if the accuracy in calculating emissions is increased by using the required methodologies. The option also insures equal treatment for in-state and out-of-state facilities. In the absence of verified emission reports from out-of-state facilities ARB will rely on data available from U.S. EPA or the Energy Information Administration.

3. Reporting Requirements and Methods.

Information to be Reported. The proposed regulation requires generating facilities to report GHG emissions from combustion, process emissions, fugitive emissions (including SF_6 and HFC sources that directly support power generation), nameplate generating capacity, fuel consumption, heat content by fuel type, carbon content if measured, annual net power generated, and power exported if known.

At the unit level, the proposed regulation requires reporting of GHG emissions, nameplate generating capacity, fuel consumption, annual net power generated, and exports if known. The information will provide a complete picture of the power and utilities sector in future analyses, plans, and regulatory programs. Operators are permitted to aggregate information for multiple generating units that combust the same fuel type if the facility lacks the necessary equipment to report by generating unit.

Retail providers that operate generating facilities are required to report information for their facilities. Retail providers and marketers are required to report power imported and exported in and out of California. There are additional requirements for retail providers related to future regulatory strategies. These include reporting ownership share, contract dates, determination of native load power, in state power purchases and sales, out-of-state owned power sold to out-of-state entities, and other information. These requirements are addressed in detail below in the discussion on the CPUC/CEC recommendations.

Retail providers and marketers are also required to report fugitive SF_6 emissions associated with transmission and distribution systems and substations located inside California and maintained by these entities. Reporting by these entities will account for roughly 95 percent of fugitive SF_6 emissions in California.

Emission Calculation Methodologies. The Act provided that ARB to consider market-based compliance mechanisms, such as a future cap-and-trade program. ARB expects that the electric power sector would be one of the first sectors to trade GHG emissions should a program be put in place. The U.S. EPA Acid Rain Program for electric generating facilities $\geq$25 MW is a national trading program for SO_2. Although U.S. EPA programs have been focused on SO_2 and criteria pollutants, the Acid Rain program does call for the reporting of CO_2 emissions from electric generating facilities. U.S. EPA's rigorous protocols provide quality assurance and quality control for the data reported under the requirements set forth in 40 CFR Part 75. The RGGI has established a source-based CO_2 trading program using Part 75 data.

Given these considerations the ARB's proposed regulation aligns California with national policies by requiring California facilities to report CO_2 emissions to ARB following the methodologies and protocols outlined in 40 CFR Part 75. Part 75 reporting is largely based on Continuous Emissions Monitoring Systems (CEMS). Appendix G of Part 75 does allow the use of fuel-based methodologies to report CO_2 emissions in some cases. The proposed ARB regulation includes additional requirements for quality assurance/quality control on fuel measurements when using a fuel-based methodology.

Whether an operator reports using CEMS or fuel-based emissions estimation methods, the proposed regulation stipulates that operator shall continue to use the same methodology for all future years of reporting in order to a maintain consistent comparison of emissions over time. An exception is provided for an operator that

installs a new CEMS within the first two years of regulation adoption; the new system must be operable before January 1, 2010, and used for emission reports thereafter.

For generating facilities that are not subject to 40 CFR Part 75, the proposed regulation reflects methodologies that meet high expectations for accuracy and are recommended in trading programs and voluntary programs already being implemented in the U.S. and abroad. Methodologies were selected for each fuel type. The methods may include fuel analysis or other specifications depending on the carbon variability of the fuel.

Fuels like biomass and municipal solid waste (MSW) are so varied that fuel analysis is impractical. The use of CO_2 CEMS is the preferred methodology for estimating GHG emissions from facilities that combust these fuels. Some facilities, however, do not operate a CO_2 CEMS. For these facilities, the proposed regulation offers conservative default emissions factors or the option to develop a source specific emission factor under the technical review and approval of ARB. Adding CO_2 measurement to an existing CEMS is another option for some facilities.

The proposed regulation requires emissions from biomass-derived fuels to be reported separately from fossil fuels. Municipal solid waste facilities are required to use ASTM Method D6866 once per quarter or season to determine the portion of emissions attributable to biomass. If generating units on a MSW facility combust fuel from a common source, only one unit needs to be tested.

For process and fugitive emissions, the proposed regulation includes mass balance methodologies provided in the CCAR protocol. These methods are also consistent with U.S. EPA programs. The proposed regulation allows for reporting fugitive emissions of SF_6 or HFC from a single unit to be based on service logs that record measured applications for that particular unit. The proposed regulation requires that fugitive emissions such as SF_6 from transmission and distribution systems be reported but does not assign responsibility for these emissions to the reporting retail provider.

There is no standardized methodology available to estimate fugitive CO_2 emissions from geothermal facilities. As a result, the proposed regulation relies on published conservative default emission factors or the option for the facility to develop a source specific emission factor under the technical review and approval of ARB.

4. CPUC/CEC Recommendations

In a joint recommendation to ARB, the CPUC and the CEC proposed a reporting and verification protocol with in-depth requirements for the electric sector (see Attachment D). Key elements of the CPUC/CEC recommendations have been incorporated into ARB's proposed regulation.

The regulation requires California's electrical retail providers to annually report all quantities of electricity generated, purchased or sold. The intention of this requirement is to provide an accurate picture of the emissions associated with electricity produced to serve each retail provider's customers. For all generating facilities owned by a retail

provider, the retail provider is required to indicate whether or not that plant is used exclusively to serve its "native load". One of several conditions must be met to make this demonstration. Similarly, the retail provider must report which power purchases are used to serve native load.

Assuring Reductions from Retail Providers. Until an efficient western states regional tracking system for power transactions is developed and implemented, it is not feasible to trace all electricity consumed in California back to the generation sources, and thus not possible to track emissions through multiple types of power transactions. A key goal of the CPUC/CEC recommendations was to minimize opportunities to shift contracts as a means of meeting future emission reduction responsibilities. Detailed provisions have been included in the regulation or in accompanying guidance to help assure emission reductions from changes in generation to serve the California load are real. This is consistent with the Act's requirements to minimize leakage from any future market-based compliance mechanisms.

"Contract shuffling" occurs when retail providers take less power from high GHG plants currently used to serve California's load, divert this dirty power to regions without GHG limitations in place, and then provide cleaner power for California customers from other existing sources. This type of transaction would create no true net reduction in emissions. To discourage this, retail providers are required to report both the amount of power taken and their ownership share of each facility. If the amount of power taken from dirty plants diverges significantly from the ownership share of the facility the retail provider must indicate why this was the case and may be assigned additional emissions.

For power purchases, retail providers must disaggregate the reported total annual amount purchased in a variety of different ways. Purchased power must be designated as originating from either specified or unspecified sources. Purchases from specified sources can be traced back to a specific generating facility, whereas purchases from unspecified sources cannot.

A special reporting requirement exists for purchases from nuclear or large hydroelectric plants[5]; retail providers must indicate the quantity of the purchase that was made through a power contract that was in effect prior to January 1, 2008 and is either still in effect or has been renewed without interruption. Since nuclear and large hydro facilities already operate at capacity, new contracts associated with existing facilities would not result in new clean generation. This reporting requirement is designed to reduce the incentive to change how the power produced by these sources is allocated in order to create the appearance of emission reductions. This disincentive is provided by assigning a default emission factor to power from new contracts with these existing sources.

[5] "Large hydro" refers to hydroelectric plants that are greater than 30 megawatts nameplate capacity and that are not California-eligible renewable resources as defined by the Public Utilities Code and the Public Resources Code.

For purchases from California-eligible renewable resources, the purchasing entity must indicate the quantity of the purchase that was stripped of its renewable attributes through separate sale of the Western Renewable Energy Generation Information System (WREGIS) certificates. Once the WREGIS certificate has been sold the power that remains is referred to as "null power". Tracking this null power information will allow ARB to potentially assign emissions characteristics to this power in the future.

Retail providers are required to report wholesale sales data disaggregated in a fashion similar to that used to track wholesale purchases (specified vs. unspecified, region of delivery, etc.).

Emissions from Unspecified Purchases. Emissions associated with specified sources can be attributed to the retail provider based on the generation details of the facility from which the power originated. Emissions associated with unspecified sources will be assigned default emission factors. Unspecified purchases, other than those from the pooled California Independent System Operator (CAISO) markets, must be reported as originating from one of three resource regions—Northwest, Southwest and California—or be designated as from an unknown region, in order to facilitate assigning emissions to these purchases.

The proposed regulation requires North American Electric Reliability Corporation (NERC) E-tags be used to verify the region of origin for unspecified sources. While retail providers are not required to report E-tag records directly to ARB, this information would be made available to verifiers.

Eventually, it is possible that each of the three regions and the CAISO markets will be assigned a unique default emission factor value, which will be updated annually (on an ex ante basis). Ideally, the regional values would be derived from a common set of rules developed by the Governors' Western Climate Initiative or through another process with multi-state input. Estimates for regional values appear highly uncertain at this time. As a result, CPUC and CEC recommend a single uniform value of 1,100 lbs CO_2/MWh for all unspecified purchases in the interim. This value is close to the Western Electricity Coordinating Council regional average and, according to the GHG performance standard implemented as a result of SB 1368, all new long-term contracts and investments in base load power imported and generated for California's use must be at least this clean.

Stakeholders have raised concerns about the contract shuffling provisions of the CPUC/CEC recommendations, including the default value of 1,100 lbs CO_2/MWh. Some commenters believe more time should be given to sort out the appropriate value for default emission factors by region. Others have advised ARB that specifying the numeric value of this default factor may immediately impact power markets and power prices. Specifically, setting this value encourages source specification by those generators that emit less than this value, which could potentially reduce participation in the CAISO markets. This potential effect on the CAISO markets could occur immediately after ARB sets this value, though ARB will not begin using the default

emission factor until late 2009 or early 2010 when the database calculates emissions from the information reported for the 2008 period. More accurate factors could become available in the interim, and the CPUC/CEC protocol recommends that a comprehensive review of these reporting requirements be undertaken by ARB in 2010, prior to the commencement of a regulatory scheme in 2012.

Specification of the interim default emission factor of 1,100 lbs CO_2e/MWh for unspecified purchases has broad consequences -- influencing emission calculations related to unspecified sources, new contracts with large hydro and nuclear facilities, and potentially how null power is treated. It would also reduce ambiguity, act as a preventive measure for contract shuffling, and encourage source specification. ARB staff has opted to include the interim factor in this staff report (Attachment C), and invites further comment. If California adopts a trading scheme based on the first-seller approach recommended by the Market Advisory Committee, some of the issues related to this factor in the context of load-based reporting (e.g., impact on the CAISO markets) would become moot points.

Finally, as mentioned above, entities that control multiple generating facilities may request that ARB establish a supplier-specific emission factor for the aggregate sales from these facilities. These sales would be assigned this supplier-specific emission factor rather than a default value.

Reporting by Power Marketers. Electric power marketers will report the amount of electricity generated, purchased, or sold. The power imported by marketers will be separated into categories depending on whether that power originated from a specified or an unspecified source, in a fashion similar to that described above for retail providers. Marketers importing power from unspecified sources will have to indicate a region of origin. Exports of power will also be reported, and separated into specified or unspecified categories. Wheel-throughs – when power is moved through California but is not consumed in the state – would also be reported by each marketer. Excessive wheeling could potentially occur to arbitrage regional emission factors, and would strain California's transmission system. By collecting wheel-through data ARB will be able to capture a complete picture of California's electricity market and to provide disincentives for excessive wheeling.

In summary, ARB has accepted the recommendations provided by the CPUC and the CEC, and incorporated these into the proposed regulation or accompanying guidance documents.

5. Other Issues

Green Power. The CPUC/CEC recommendations were silent on the issue of environmentally differentiated retail electricity products offered by retail providers. For these products, retail providers purchase renewable energy and renewable energy credits specifically to meet the energy use of green energy customers who pay a premium for this power. The proposed regulation allows retail providers to report green power retail sales separately from other retail power sales.

Transmission and Distribution Losses. The Act requires that GHG emissions from all electricity consumed in California be accounted for, including transmission and distribution line losses. To fully address line losses, they must be considered in three types of power transfers: in-state generation, specified purchases, and imported unspecified purchases. First, because emissions from power generation are reported by facility operators at the source of generation, line losses are accounted for before they occur. Next, retail providers are required to report power purchased from specified sources as measured at the "busbar" or at the source of generation, again to account for line losses before they occur. Last, since line losses associated with power imported from unspecified sources cannot be determined and those contracts are measured from the first point of receipt inside California, the emission factor used with unspecified sources will be adjusted upward to reflect out-of-state upstream transmission losses consistent with the ARB emissions inventory.

Database Subroutines. The ARB database will include a number of internal subroutines to calculate GHG emissions. Subroutines will match power purchases and sales from specified sources to emissions reported by the corresponding generating facility. Unspecified purchases and sales will be matched with the appropriate regional default emission factor.

Interim guidance that accompanies the proposed regulation will also include formulas to calculate certain emission factors. The ARB database will use the retail sales emission factor formula provided in the guidance to calculate an emission factor specific to each retail provider. This emission factor will in turn be used to calculate emissions from power used by retail customers. The calculations will include the option to calculate green power products sold at a premium to retail users. Similarly, there will be a subroutine that utilizes the emission factor formula for unspecified wholesale sales and matches the emission factor to unspecified wholesale sales reported by the retail provider.

In addition, subroutines would be added to calculate emission responsibilities assigned to retail providers under a load-based cap and those assigned to first sellers under a first-seller approach. Last but not least, there will be subroutines to calculate statewide inventory totals and subtotals.

All of these formulas are provided in the guidance document that accompanies the proposed regulation. The formulas are written as separate components in order to distinguish fundamental emissions calculations based on power taken and source specific emissions from emission adjustments needed to calculate load-based emission responsibilities based on ownership shares and emission penalties tied to contract shuffling.

CEMS versus Fuel-Based Methods. In many cases, the proposed regulation provides the option for a reporter to use either a fuel-based methodology or one based on data from continuous emissions monitoring systems (CEMS). Because these are different

methodologies they will yield somewhat different results. The issue is most pronounced with coal facilities, coal being a solid fuel that is more difficult to measure and analyze. Differences in CO_2 emissions provided by the two methods typically range between 5 and 10 percent. There are arguments on both sides that support the accuracy of these methods. The U.S. EPA Acid Rain Program relies exclusively on CEMS data for coal plants; yet, other trading programs acknowledge fuel-based methods as well.

An additional concern is that CEMS data was not available in 1990, the Act's target year. Thus, there are inconsistencies between ARB's 1990 GHG inventory and the information that will be collected under mandatory reporting. As discussed in Section II of this report, ARB staff is of the opinion that methodologies now thought to be accurate and accepted worldwide should not be excluded from mandatory reporting simply because they were not available in 1990. All methodologies under mandatory reporting will produce somewhat different emissions from the 1990 inventory because these calculations will be based on fuel analysis techniques and source specific information not available in 1990.

Stakeholders have expressed strong preferences for either a CEMS or a fuel-based methodology, and ARB does not propose to limit the choice among sound methodologies at this time. However, the proposed regulation does require that fuel usage be reported even for facilities that use CEMS data. This information will enable ARB to conduct comparisons. The proposed regulation also requires a reporter to select the methodology of choice and continue all future reporting using the same method in order to secure consistency in the future. Future regulations and possible trading schemes will need to consider the fact that emissions from mandatory reporting will be more accurate and different from prior emission calculations when setting base years or emission allocations, and make adjustments accordingly. ARB staff will continue to work with stakeholders to assess the reasons for differing results from the two methods of estimating emissions.

Electrification of Ports and Motor Vehicles. Strategies to reduce greenhouse gases can include the electrification of sea ports, truck stops, and motor vehicles. The emissions associated with increased electricity usage would seem to fall on power generators and retail providers. In the proposed regulation, retail providers may report retail sales associated with the electrification of ports, etc. as a first step to tracking this increase in electricity usage.

C. Cogeneration Facilities

1. Background

The Act requires monitoring and reporting of greenhouse gas emissions (GHG) from the sources that "contribute the most to statewide emissions." Emissions from the generation of electric power are the largest category of point source emissions in the GHG inventory. Since cogeneration facilities sequentially generate electricity and thermal energy, and offer unique opportunities for reduced emissions from increasing

efficiencies in the industrial sector, staff has proposed their inclusion in mandatory reporting.

Cogeneration associations participated as stakeholders in the GHG Power/Utilities Technical Discussion group meetings in the spring. In early June, staff met with the California Cogeneration Council (CCC), Cogeneration Association of California (CAC) and Energy Producers and Users Coalition (EPUC). The associations requested that the regulation include a separate sector for cogeneration facilities. Because of the unique technical qualities of cogeneration, including the need to allocate or distribute emissions to both thermal and electrical outputs, staff agreed that GHG reporting requirements for cogeneration facilities should be separately specified in the regulation.

Staff received initial input on reporting methods from the cogeneration associations and U.S. EPA staff involved in the Combined Heat and Power (CHP) Partnership program. Based on that input, staff presented the initial concepts "Cogeneration: Proposed Approach for Mandatory Greenhouse Gas Emissions Reporting" in June 2007 (CARB 2007) during three technical discussions with affected sectors: refineries, power/utilities and general stationary combustion. Staff requested and received stakeholder comments on the proposed approach. The commenting parties were then invited to participate in a cogeneration focused technical discussion group to discuss stakeholder recommendations for mandatory reporting on July 24, 2007. Staff included in the August 10 preliminary draft regulation the initial concepts from the proposed approach as well as some changes recommended by stakeholder input. In response to a recommendation to provide additional guidance, staff held a second cogeneration focused technical discussion group meeting on August 23, 2007, and prepared revisions to draft regulatory language. After consideration of additional comments received on the draft methods, staff prepared the final proposed regulation.

2. Basis for Proposal

In consultation with stakeholders, staff reviewed existing GHG emissions reporting programs to determine the methodologies for estimating greenhouse gas emissions from cogeneration facilities. The California Climate Action Registry (Registry) (CCAR 2007a), World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD 2001), Department of Energy /Energy Information Administration (USDOE 2007), U.S. EPA Climate Leaders (USEPA 2004), and the UK Emissions Trading System (DEFRA 2003) reporting programs require reporting of stationary combustion emissions as direct emissions; the variations are in the methods used to distribute the emissions between thermal energy and electricity generation outputs.

The methodologies reviewed by ARB staff included the Work Potential and Energy Content methods to distribute GHG emissions from cogeneration facilities to each of the energy stream outputs generated on-site. These allocation methods were not recommended for mandatory reporting because they are limited in application to specific types of cogeneration facilities. Staff also considered the California Public Utilities Commission (PUC) Conversion Method, which assumes the same efficiency for

both energy stream outputs. Staff found this may oversimplify the allocation of emissions because it ignores the relative efficiency of electricity generation and thermal energy production. Staff presented these options to key stakeholders and received informal comments, which predominantly supported adoption of the Registry Efficiency Method to distribute stationary fuel combustion emissions between thermal energy and electricity generation.

The Registry Efficiency Method allocates GHG emissions to each energy stream output of a cogeneration facility based on the efficiencies of thermal energy and electricity production. This method assumes that conversion of fuel energy to thermal energy generation is more efficient than electricity generation. Although the Registry Efficiency Method allows cogeneration facilities to use actual cogeneration system efficiencies, none of the existing GHG program protocols includes a method to calculate these efficiencies. Stakeholders requested ARB provide guidance on how facilities should calculate actual cogeneration system efficiency values.

Staff worked closely with stakeholders to develop equations to calculate facility-specific electricity generation and thermal energy production efficiency values. These equations were provided in the August 10, 2007 preliminary draft regulation. Topping cycle plants that generate electricity first and send thermal energy to a process after electricity generation were required to calculate a facility-specific electricity generation efficiency value, but, had the option to use a default value, the manufacturers Heat Recovery Steam Generator Rating, or calculate a facility-specific thermal energy efficiency value. It was determined that facilities could not calculate both efficiency values using the formulas provided and maintain the energy balance for all cogeneration systems. This version of the regulation included a placeholder for a detailed efficiency method. Since ARB received a recommendation to treat bottoming cycle plants differently than topping cycle plants, the August 10 draft also included a placeholder for bottoming cycle plants.

Bottoming cycle plants recover steam or heat from a process stream to produce electricity at the bottom or end of the cycle. One of the cogeneration associations suggested that ARB require bottoming cycle plants to allocate all of the CO_2 emissions from fuel combustion to the thermal energy production, because electrical generation is a product of waste heat. This option would suggest that the electricity generation be considered a carbon-free product. Staff did not include this option in the regulation because a more thorough, plant-specific determination of additionality is needed to assess whether the electrical generation should be considered free of carbon. This leaves the door open to possible future development of project protocols for this purpose.

In an effort to develop a separate method for bottoming cycle plants, staff evaluated a detailed efficiency method included in the WRI/WBCSD program. Staff determined this method was not applicable for bottoming cycle plants that produce multiple product outputs such as steam, electricity, and hydrogen. Therefore, staff developed a detailed efficiency method that assigned emissions to the manufacturing process, thermal energy, and electricity. Staff initially suggested an energy balance approach with

revised equations for topping cycle plants to calculate both the electricity and thermal energy efficiency values, but this was not supported by most stakeholders, who suggested that the additional guidance for determination of fuel inputs to produce electricity and thermal energy would require new equipment, while the additional calculations would provide only perceived accuracy.

Staff prepared another option that would require facility operators to use an average 80 percent thermal energy efficiency value and calculate a facility-specific electricity generation efficiency value. The U.S. EPA CHP Partnership pointed out that under this approach there was at least one cogeneration system where the calculated electricity efficiency would be 10 percent. This calculated efficiency resulted in more emissions distributed to electricity generation than what would have been estimated as electricity emissions in a separate heat and power (SHP) system. Staff determined this method may result in inaccurate emissions distributions for some cogeneration systems.

After exploring these options, staff determined there may not be one method that allows every cogeneration system to be treated equitably. Even the Registry acknowledges that "the use of default efficiency values may, in some cases, violate the energy balance constraints of some CHP systems." The Registry allows facilities to modify the efficiency values until the constraints are met. Based on the level of complexity with cogeneration systems, staff provided options in the final proposal. This approach provides reporters with some flexibility in determining efficiency values, which is consistent with the Registry Efficiency Method.

3. Reporting Requirements and Methods

Under the staff proposal, cogeneration facilities with electricity generation capacity greater than or equal to 1 megawatt (MW) with annual GHG emissions of 2,500 metric tonnes or more from generating activities, or within the operational control of another facility subject to this regulation, are required to report annual CO_2, CH_4, and N_2O emissions from fuel combustion. Cogeneration facility operators must report annual GHG emissions from processes and fugitive sources as required for electric generating facilities, if applicable to their facilities.

The final proposal includes separate reporting requirements for topping cycle and bottoming cycle plants. Operators of topping cycle plants are required to report distributed fuel combustion emissions between the thermal energy and electricity using the Registry Efficiency Method. Bottoming cycle plant operators are required to report distributed fuel combustion emissions between the thermal energy, electricity, and manufactured products using a detailed efficiency method. These distributed emissions provide information for on-site direct users and downstream indirect users of the energy purchased and consumed.

Both topping cycle and bottoming cycle plant operators can use either a default efficiency value of 80 percent or a manufacturer rating for thermal energy production efficiency. They may also use a default efficiency value of 35 percent or calculate a facility-specific electricity efficiency value, which is equal to annual net power generated

divided by total fuel input. Once the topping cycle thermal energy production emissions are estimated, they are subtracted from the total to determine emissions distributed to electricity generation. Bottoming cycle plants would be required to calculate distributed emissions using a detailed efficiency method. The detailed efficiency method includes a methodology to estimate emissions assigned to the manufacturing process. Once the thermal energy emissions and manufactured product emissions are determined, they are subtracted from total emissions to estimate the emissions associated with electricity generation.

By adopting the Registry Efficiency Method, ARB is following the policy direction of the Act to adopt Registry protocols whenever possible. Most informal comments received from stakeholders recommended that ARB adopt this method. It is also preferred by the World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD) and U.S. EPA Climate Leaders. Staff included efficiency methods with built-in flexibility in the final proposal as the most equitable approach to distribute cogeneration facility emissions between energy stream and product outputs.

D. Petroleum Refineries, Hydrogen Plants, and Combustion from Oil-and-Gas Production

1. Background and Basis for Proposal

Staff has made petroleum refinery sources a high priority for first-year reporting due to their significant share of GHG emissions in California. One key source of GHGs at refineries, hydrogen production, also occurs at offsite production facilities under separate operational control. To assure fairness across the sector hydrogen production plants are addressed separately in the regulation, with an annual CO_2 emissions threshold of 25,000 metric tonnes triggering the hydrogen plant reporting requirement for separate facilities. When hydrogen plants are operated by the refinery their emissions are included, but separately specified, in the refinery emissions report. Hydrogen plants under separate operational control would report their emissions directly.

While evaluating the oil and gas production sources in the general stationary combustion sector, staff encountered similar factors related to fuel variability as those encountered in the refineries sector. For this reason the regulation specifies combustion emissions calculation methodologies for oil and gas production sources that are similar to those of refineries. Petroleum refineries, hydrogen plants, and combustion emissions from oil and gas production sources are all addressed in this section of the staff report.

In contrast to the other major sectors brought into mandatory reporting, ARB did not have an industry-specific California Climate Action Registry Protocol to inform and guide development of calculation methods for the regulation. The basic governing principles below guided ARB staff during the development of a GHG reporting methodology for

California's petroleum sources, as they have guided CCAR staff in their reporting protocol development work.

The basic and guiding principles critical to the development of a credible greenhouse gas reporting program have been discussed in detail by the World Resources Institute (WRI) and World Business Council for Sustainable Development (WBCSD) in their 2001 report entitled *The Greenhouse Gas Protocol, A Corporate Accounting and Reporting Standard.* In fact the California Climate Action Registry based their General Reporting Protocol (2007) on the principles set forth in this WRI/WBCSD document. WRI/WBCSD concluded that fundamentally, a greenhouse gas reporting methodology must be:

1) Relevant – in that it must contain all the information that is required both internally by the reporter and externally, necessary and sufficient to support an informed decision making purposes;
2) Complete – such that all relevant emission sources within the reporting boundary are accounted for;
3) Consistent – so that GHG emissions information may be tracked and evaluated over time;
4) Transparent – providing that all procedures, processes, assumptions and limitations are clearly defined and understandable, and finally;
5) Accurate – the data contained in the final GHG emission report must be sufficiently precise to facilitate a credible decision making process.

Overview of the Process. Throughout all phases of the regulatory development process ARB staff has solicited input from a host of stakeholders. A Refinery Sector Technical Team composed of approximately 85 individuals was established in the spring of 2007, including individuals who signed on at the February 28 workshop. Industry representatives, environmental organizations, consulting companies, and public interest groups were all involved in the process. At the four technical team meetings staff led discussion on proposed petroleum GHG reporting methods and solicited input from all participants. As part of the regulatory development process, ARB staff participated in fact finding tours at two California petroleum refineries, visited an oil and gas production field, met often with industry representatives and interested parties at ARB headquarters and consulted air district experts.

2. Guidance Consulted

In addition to input from many stakeholders, a number of documents provided valuable guidance in all aspects of this process including the following:

California Climate Action Registry. The Act directs that ARB incorporate, where feasible and appropriate, the standards and protocols of the California Climate Action Registry (CCAR). The CCAR General Reporting Protocol (GRP) provides a standardized approach to the reporting of GHG emissions. CCAR does not have approved protocols specific to the petroleum industry, however. To assist development of the ARB Refinery GHG reporting regulation, CCAR produced a "*Discussion Paper for a Petroleum Refining Greenhouse Gas Accounting and Reporting Protocol*", a draft version of which

was released on July 9, 2007. This document also was consulted and provided valuable guidance.

Industry Technical Documentation. Many industry publications were consulted and provided both general and industry specific technical guidance. General information on the design and boundaries of refinery GHG reporting was found in the International Petroleum Industry Environmental Conservation Association (IPIECA) 2003 publication - *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*. Numerous Canadian Association of Petroleum Producers (CAPP) documents, while primarily focused on the upstream segment (exploration and production) of the industry, were very helpful as well. The *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry* produced by The American Petroleum Institute (API 2004) is a comprehensive 480 page document which discusses GHG emissions from a wide range of industry sources from the exploration and production fields, the refining process and product distribution. Methodologies presented in this API document provided the basis for many of the reporting methods incorporated in these regulations.

Established Federal and State Rules and Regulations. Whenever practical, staff endeavored to base industry specific GHG reporting methods on existing federal, State, and local rules and regulations. We feel that the use of existing data generation and reporting rules helped to avoid or at least minimize additional burdens imposed on reporters while at the same time providing established and consistent emission reporting methods. California Air Pollution Control District (APCD) and Air Quality Management District (AQMD) industry specific rules and regulations form the basis for several of the GHG reporting methods included in these regulations. Fugitive emission Leak Detection and Repair (LDAR) procedures developed by the California Air Pollution Control Officers Association (CAPCOA) for fugitive emission quantification have also been incorporated. LDAR programs are currently in operation at most of the California refineries.

US EPA methods and pollution control measures were also incorporated in these regulations. In all instances these regulations were already in effect in California refineries, thus insuring consistent industry-wide GHG reporting.

International Monitoring and Reporting Guidelines. ARB staff relied on the wealth of experience and expertise of numerous international organizations and agencies that have developed and administered Greenhouse Gas Monitoring and Reporting Programs for some time now. The Intergovernmental Panel on Climate Change (IPCC) has developed and published extensive guidance documentation in support of greenhouse gas inventories (e.g. IPCC 2006). The Commission of the European Communities guidelines for monitoring and reporting GHG emissions and European Union Emissions Trading Scheme (EU ETS) Member States publications also provided valuable knowledge and direction.

3. Reporting Requirements by Refinery Source

Overview. An evaluation of the relative magnitude and materiality of greenhouse gas emissions sources is a critical first step in the development of an accurate, complete and relevant GHG accounting structure. It is essential that the reporting methodologies adopted for all large, very material GHG sources be rigorous and as accurate as possible. The outcome of the decision making process which follows, and ultimately the success of the California Global Warming Solutions Act of 2006 depends on an accurate, precise and complete GHG accounting.

California's twenty-one petroleum California refineries produce about 7 percent of the annual GHG emissions in the state. Important GHG sources within these refineries include the combustion of a variety of fuels, which generates 50 percent or more of annual refinery GHG emissions. On average, process emissions contribute an equally large fraction of refinery GHG emissions. Together these two sources, combustion and process related emissions, account for over 90 percent of all refinery GHG emissions. Fugitive and flaring GHG emissions contribute less than 10 percent to annual GHG totals.

Attachment F, on refinery GHG reporting provides a more detailed discussion of the important technical concerns considered by staff in developing the proposed requirements for refineries and related sources.

Stationary Combustion GHG Emissions. As stated above, stationary combustion emissions are a very important and material part of the annual GHG footprint of a typical California refinery. Thus, accounting methods for this source must be rigorous and accurate. Carbon dioxide, methane and nitrous oxide are released to the atmosphere as the result fuel combustion. Emissions of CH_4 and N_2O represent a very small fraction (1-2 percent) of this GHG combustion output and thus it is appropriate to adopt less stringent accounting methods in the case of these two GHG gases.

The first step in accounting for combustion GHG emissions is identification of the important fuels combusted in a refinery to produce the thermal energy required in the crude oil refining processes. Refinery fuel gas and natural gas are the two predominant fuels used in the refining process. Refinery fuel gas (RFG), which typically represents 50 percent or more or refinery fuel, is generated from the crude oil feedstock as a result of a variety of processes that take place at the refinery. Refiners capture RFG and use it to fuel devices such as heaters, boilers and furnaces. Thus, the combustion of RFG contributes a very significant (≥40 percent) fraction of refinery GHG emissions and it is essential that we adopt accurate methodologies to quantify this very substantial source of GHG emissions.

One fact that complicates our efforts to accurately quantify RFG combustion related GHG emissions is the variable nature of this fuel. Refineries typically have from one to four separate and distinct RFG collection and distribution systems. Each of these systems collect crude oil derived gases from very different processes taking place in the refinery, and consequently the carbon and energy contents of these RFG systems are

distinct. It is apparent that if reporters are to accurately determine CO_2 emissions resulting from RFG combustion, it will be necessary to precisely quantify the fuel composition of each of the RFG systems in their refinery.

A method requiring the daily measurement of RFG High Heating Value (HHV – Btu/standard cubic foot of fuel) and carbon content (weight percent carbon) was developed. This method is an enhancement of preferred API methodologies and CCAR GRP approaches. Refinery operators are thus able to calculate and use a fuel gas system specific emissions factor to calculate CO_2 emissions - inherently a much more accurate method than using a default emissions factor. Additionally, the use of a daily average refinery fuel high heating value in this calculation enhances calculation accuracy by integrating this fuel variable over a 24 hour period. European Union Emission Trading System (EU ETS) guidelines also stipulate daily analysis of refinery fuel gas. Details may be found in the Attachment E technical discussion.

While natural gas is also a very important fuel used extensively in California refineries, the composition of this fuel is much less variable. The composition of commercially traded fuels such as natural gas and distillate fuels must meet exacting specifications, and thus it is appropriate to use a less stringent sampling methodology and a less frequent measurement regime. Methods based on fuel activity data and monthly HHV data, consistent with API and CCAR GRP methods are specified in this case.

As stated above, combustion emissions of methane and nitrous oxide are very small. CCAR General Reporting Protocol methods relying on default emission factors have been adopted in this case.

Process Emissions for Refineries and Hydrogen Plants. Like fuel combustion, GHG emissions of CO_2 resulting from the various crude oil distillation, cracking, reforming and product treatment processes also represent a significant fraction of a refineries emissions. Catalytic cracking and hydrogen production process GHG emissions are the major contributors.

> Catalytic Cracking – An API preferred method was adopted for the determination of CO_2 emissions resulting from the regeneration of refinery catalysts. This API based method requires refiners to determine the rate at which coke is burned off the catalyst during the regeneration cycle. To insure consistency, an EPA method for the calculation of the coke burn rate was specified. The EPA coke rate method is specified as part of Title 40, which regulates the emission of hazardous air pollutants from petroleum refineries. Thus the required instrumentation is in place at California refineries and personnel are familiar with these procedures.
>
> Hydrogen Production – The production of hydrogen generates large quantities of carbon dioxide derived from the wide variety of hydrocarbon feedstocks that serve as the hydrogen source. These process CO_2 emissions are large,

representing perhaps 20 percent of refinery annual GHG emissions, thus requiring accurate and precise accounting methods.

One of two preferred API methodologies has been modified and adopted for the calculation of hydrogen plant emissions. Modifications to the basic API formula were requested by industry in order to insure that this methodology would be applicable to all the operational variations that are encountered in California hydrogen plants. Details of the technical issues and modifications required are found in Attachment E.

Hydrogen plant operators typically use a widely variable mixture of hydrocarbons as feedstock. The variable nature of the feedstock requires accurate and frequent determination of carbon content if we are to accurate quantify GHG emissions. Thus we have specified a daily measurement frequency. At the request of industry representatives, we have included provisions that permit the use of Continuous Emissions Monitoring System (CEMS) technology to monitor and quantify both process and combustion emissions from hydrogen plants. Hydrogen plant operators will be required to operate CEMS in accordance with Federal Regulations 40 CFR Part 60 or 40 CFR Part75. These Federal regulations also apply to power plants, thus insuring consistency among all CEMS users. A disadvantage of CEMS reporting, however, is the loss of resolution of combustion and the production processes emissions. For this reason the proposed regulation seeks reporting of fuel usage for all sectors, though ARB staff understands the particular commercial sensitivity of separate specification of emissions in the hydrogen production sector.

Hydrogen plant operators may also recover and sell carbon dioxide. The EU ETS refers to this GHG stream as "transferred CO_2" and commercial uses include beverage carbonization and the production of dry ice. We have included a provision in the regulations which allows hydrogen plant operators to report transferred carbon dioxide. The establishment of accounting procedures and responsibility for GHG streams such as transferred CO_2 is not the intent of the proposed regulation, and thus at the present time transferred CO_2 is not to be subtracted from a facilities emission report.

GHG accounting methodologies for three additional sources, process vents, asphalt production operations, and sulfur recovery, are also included in the proposed regulation. These three sources represent relatively minor GHG sources when compared with the large combustion and process emission sources discussed above. Thus, less rigorous methods are applied to these sources. These methods are discussed briefly below, and in more detail in Attachment E.

Asphalt Production – A number of California refiners produce asphalt products for a wide range of applications, such as highway construction and roofing materials. Hydrocarbon emissions from the asphalt production process are

controlled, typically by incineration. We have adopted a simple GHG accounting method, based on the annual amount of asphalt substrate produced, that incorporates a U.S. EPA derived emission factor. This method does not require the installation of additional equipment. GHG emissions from uncontrolled asphalt product storage tanks are addressed in the fugitive emissions section of the regulation, and a short discussion of this method is found below.

Sulfur Recovery – An integral step in the production of clean transportation fuels is the removal of sulfur. Inevitably, carbon dioxide and hydrocarbons are entrained in the many gas streams that are sent to refinery Sulfur Recovery Units (SRU) for treatment. Ultimately this carbon is released as CO_2 at one or more points in the sulfur recovery process. A method for the calculation of CO_2 emissions is therefore included in these regulations. The method is drawn from the API and requires only that operators monitor flow to refinery SRUs. A provision has been included in this section which provides the opportunity to develop a site specific emissions factor. Operators must obtain ARB approval of the sampling plan prior to use.

Fugitive Emissions. Typically, fugitive emissions represent a relatively small fraction (≤10 percent) of a refineries GHG footprint. By their very nature, and as the term fugitive implies, these emissions are difficult to measure and quantify. Thus there remains a relatively large degree of uncertainty as to the magnitude of these GHG sources. Accounting methods for four fugitive sources -- wastewater treatment, storage tanks, oil/water separators, and equipment fugitive emissions -- have been included in these regulations. In most cases it was possible to base these methods on existing State monitoring rules in regulations already in place, thus minimizing the additional effort required. The accounting measures adopted for these four sources are discussed below.

Wastewater Treatment – Methods based on IPCC prescribed procedures (IPCC 2006b) have been adopted to calculate CH_4 and N_2O emissions resulting from refinery wastewater treatment operations. These methods require periodic measurement of wastewater Chemical Oxygen Demand (COD), wastewater volumetric flow, and the estimation of the mass of sludge removed from treatment facilities and the degree of anaerobic treatment that takes place.

Oil/Water Separators – We have adapted a basic GHG calculation equation and emission factors present by CONCAWE, a European petroleum trade organization. Emission factors are based on the type of separator and emission control technology applied. This method requires only that reporters determine the volume of wastewater treated in refinery oil/water separators.

Storage Tanks – Emissions of volatile hydrocarbons from crude oil and product storage tanks is an issue that has been extensively addressed by both federal and State regulatory agencies. After evaluating two computer models designed to calculate storage tank emissions (API and EPA), and consulting with industry

experts, we have chosen to use the U.S. EPA TANKS model (Version 4.09D, 2005, USEPA 2005) to calculate methane emissions from uncontrolled crude oil and asphalt storage tanks. The model software and User's Manual are available at no cost from the U.S. EPA. The operator enters detailed information concerning the facility's storage tanks and the program provides a detailed emissions report. On-line help for each screen is provided along with an extensive *Frequently Asked Questions* section.

Equipment Fugitive Emissions – California refiners are required by AQMD/APCD rules and regulations to establish a Leak Detection and Repair (LDAR) program at their facilities. These LDAR programs are based on methods established by the U.S. EPA (Method 21). API identifies the LDAR method as a preferred approach for the examination of leaking components at petroleum refineries. Thus we have chosen to use a CAPCOA/CARB (1999) method for estimating fugitive CH_4 emissions, which will require refiners to extend their existing LDAR program to all components of their natural gas and refinery fuel gas system.

Flaring – As was the case with fugitive emissions, we have chosen to adopt a GHG accounting methodology for flaring emissions that is based on existing AQMD/APCD rules and regulations. Refiners will use flare emissions data currently collected and reported to their local AQMD/APCD. A default flare destruction efficiency value will be used to scale reported emissions numbers to calculate CO_2 combustion emissions at each flare. Provisions have been included in the regulation to allow refiners to follow current reporting requirements in their respective air districts.

Additional Reporting Requirements. In addition to the GHG sources discussed above, refiners are required to report their indirect energy purchases and GHG emissions from cogeneration facilities under their operational control. The regulatory development process for these emission source accounting procedures is discussed elsewhere in this report.

4. Requirements for the Oil and Gas Exploration and Production Sector

Facilities in the oil and gas exploration and production sector are required under the proposed regulation to report their GHG stationary combustion, hydrogen production and cogeneration GHG emissions. Procedures for estimating emissions from hydrogen production are addressed above, while cogeneration methods are addressed in Section III.C of this report. Stationary combustion requirements are discussed briefly below. As discussed in Section II of this report, additional reporting requirements will be developed in the future for process and fugitive emissions from oil and gas exploration, production, processing, transmission and distribution.

Oil and Gas exploration and production facilities are required to use the same fuel specific methodologies and sampling frequencies specified for petroleum refinery operations to calculate CO_2, CH_4, and N_2O stationary combustion emissions. Logistical issues may arise as a result of the daily sampling frequency required for refinery fuel

gas system, given the dispersed nature of combustion sources in oil and gas production fields. E&P operators should refer to the de minimis provisions of the regulations to carefully evaluate the various gas streams which are combusted in the production fields. Determination of typical HHV for a gas stream along with estimates of annual gas usage will allow operators to determine if combustion emissions from a gas stream exceed the 10,000 metric tonne emissions threshold. If emissions fall below this threshold the regulation specifies that less stringent emission accounting procedures may be used. In addition, if natural gas recovered and combusted in the oil and gas production fields meets pipe line quality specifications, the methodologies specified for natural gas may be used.

E. Genera l Stationary Combustion (GSC) Facilities

1. Background

The Act requires the mandatory reporting of GHGs from the sources or categories that contribute the most to statewide emissions. In addition to the cement, electric power, refineries, hydrogen plants, and cogeneration sectors, staff identified the category of large stationary combustion sources. For the purposes of mandatory reporting, a "general stationary combustion" (GSC) facility is defined as a facility that emits greater than or equal to 25,000 metric tonnes of CO_2 per year from direct stationary combustion. Examples of some GSC facilities that could be required to report are shown in Table 3 below.

Table 3. Examples of Major Stationary Combustion Sectors Potentially Affected*

Natural gas transmission	Oil production
Industrial gases	Food processing
Paperboard manufacture	Steel foundries
Colleges and universities	Mineral processes
Glass container	Malt Beverages

*Note: Must also exceed 25,000 metric tonne CO_2 threshold to be subject to reporting.

Staff invited general stationary combustion facilities to participate in ARB's public rulemaking process. Invitations were mailed for a workshop held May 23, 2007, and then for a more focused technical discussion meeting to address these sources held on June 25, 2007. ARB staff worked with air district emissions inventory staff at through the California Air Pollution Control Officers Association (CAPCOA) to check our source contact information in the respective districts. District staff also helped ARB identify additional sources.

The methodologies and reporting requirements for general stationary combustion facilities are based largely on the General Reporting Protocol developed by CCAR.

That protocol was originally based on reporting documents developed by the World Resources Institute.

2. Basis for Proposal

In determining the applicability threshold, staff used available data in the California Emission Inventory Development and Reporting System (CEIDARS) database as reported to ARB by districts. The most complete year of data in CEIDARS was for 2004, and included data on fuel usage by fuel type and process data. By applying emission factors for CO_2 to the amount of fuel and process data, staff was able to estimate CO_2 emissions from permitted stationary combustion. In total, the 2004 CEIDARS database provided estimated CO_2 emissions for over 7,000 facilities in the state. The electric power, cement and refineries sectors accounted for approximately 72 percent of the total CO_2 from permitted stationary combustion in the 2004 CEIDARS inventory.

After searching the literature and reviewing existing GHG reporting programs staff examined several possible reporting thresholds that would require reporting by large combustion sources. Some existing reporting programs use CO_2 equivalents to evaluate threshold applicability. Staff chose to use CO_2 for the purposes of this regulation for the sake of simplicity for facilities attempting to determine whether they are subject to reporting.

Using the list of statewide permitted facilities and their estimated CO_2 emissions for 2004, staff applied a potential reporting threshold of 10,000 metric tonnes (MT) of CO_2. This threshold would bring in over 300 facilities for mandatory reporting and raise the portion of the point source CO_2 inventory estimated from CEIDARS that would be included in reporting to 96 percent, up from 72 percent with just sector specific reporting. When a 25,000 MT threshold was applied to the list of statewide permitted facilities, approximately half of the 300 facilities under the 10,000 MT threshold fell out, but the remaining facilities still allowed for inclusion of an additional 22 percent (and a total of about 94 percent) of the stationary CO_2 inventory estimated from CEIDARS. Staff finds that the doubling of facilities subject to reporting under a 10,000 MT threshold, when only improving the inventory capture by 2 percent compared to a 25,000 MT threshold, is not a worthwhile extension of the reporting burden. The 25,000 MT threshold is also used in the European Union reporting program.

3. Reporting Requirements and Methods

Under the staff proposal those subject to reporting as general stationary combustion sources will be required to report direct emissions from stationary combustion, as well as indirect energy purchased or acquired and consumed onsite. These sources would also report fuel usage by type. A GSC facility with an electric generating unit or units with a total nameplate generating capacity $\geq$1 MW that emits 2,500 metric tonnes of CO_2 would be required to meet the requirements for reporting by electric generating facilities for those units. Backup generators are not counted toward these totals. A GSC facility with a co-generation plant would be required to quantify and distribute cogeneration emissions as required in the cogeneration section of the regulation.

Since this general category of sources pulls in facilities from several different industrial sectors, the proposed regulation would require only the reporting of direct combustion emissions, and not any process or fugitive emissions. Certain industrial sectors in this category may have process emissions associated with them, and staff will consider the addition of requirements for process emissions for particular sectors (e.g., glass manufacturers, mineral processors) in future amendments to the regulation.

Emissions Calculation Methods. In reporting the direct emissions associated with combustion, operators will use the same methodology as provided in the General Reporting Protocol developed by CCAR (CCAR 2007). For each fuel type, the annual amount of fuel combusted will be multiplied by a CO_2 emission factor to provide annual CO_2 emissions. Operators have the option of simply applying the fuel specific default emission factors provided by ARB or developing a fuel specific emission factor for the facility using alternative methods provided in the regulation. Since most general combustion sources will be burning fuel that is unlikely to vary much in carbon content, staff believes default emission factors are sufficient to characterize direct combustion emissions from these sources.

The proposed regulation requires one sector subject to mandatory reporting, the crude oil and gas exploration and production sector (NAICS Code 211111) to use the methods required of refineries to quantify direct combustion emissions. This sector is known to use fuels with high potential carbon content variability, and staff believes use of default emission factors would be insufficient to characterize the emissions from those fuels.

In reporting combustion related emissions, operators would also report CH_4 and N_2O emissions for each type and amount of fuel annually combusted. To determine these emissions, operators would rely on emission factors provided in Appendix A to the regulation. At this time, there are no acceptable methodologies other than default emissions factors to quantify emissions for these two greenhouse gases. The regulation allows for the development of facility-specific emission factor for CH_4 and N_2O through source test methods approved by ARB.

Consistent with other sectors, each operator would also report the facility's purchased or acquired energy usage from electricity and thermal sources, which are generally available from billing statements. These would simply be reported as kilowatt hours (kWh) or British thermal units (Btus), along with the energy provider and indication as to whether a special "green power" purchase was made.

F. Emission Factors

1. Selection of Emission Factors

ARB released a placeholder list of default emission factors with the preliminary draft version of the proposed regulation on August 10, 2007. Throughout the proposed regulation an effort was made to preserve consistency with the CCAR reporting methodologies, and the ARB draft list was primarily based on the factors suggested in

CCAR's 2007 General Reporting Protocol (CCAR 2007). However, ARB staff received multiple comments suggesting that more current emissions factor values are available and should be used for the sake of accuracy.

As a result, the updated values released with the proposed regulation are drawn primarily from the Intergovernmental Panel on Climate Change's *2006 IPCC guidelines for National Greenhouse Gas Inventories* (IPCC 2006) and the U.S. Environmental Protection Agency's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005* (EPA 2007). In addition, California specific emission factors adapted from CEC sources have been provided for some fuels and sources.

The emission factors in Appendix A to the regulation would be adopted by reference as part of the regulation. CCAR also plans to update its emission factors in the near future. Harmonization between ARB and CCAR emission factors will continue to be a goal for ARB.

Global warming potential (GWP) values for various GHGs have been included in the *ARB Compendium* to facilitate CO_2 equivalent calculations. ARB is using the GWP values from the IPPC Second Assessment Report (IPCC 1996) in order to maintain consistency with current ARB GHG inventory development. Calculation of CO_2 equivalent emissions under the SAR is planned for ARB's online emissions reporting tool. Such calculations are generally unnecessary on the part of operators filing emissions reports, except in the determination of CO_2 equivalence for *de minimis* emissions calculations.

IV. GREENHOUSE GAS VERIFICATION REQUIREMENTS

A. Background

The Act requires the reporting and verification of greenhouse gas (GHG) emissions. Independent verification of reported GHGs is expected under international standards and is integral to many existing GHG reporting programs, including the California Climate Action Registry's voluntary program. By their nature, calculating and reporting of GHG emissions can be a complex exercise in tracking emissions sources, applying appropriate emission factors and methods, and tracking financial records. Calculation and verification of GHG emissions requires a systematic approach.

ARB staff is proposing to use independent third-party verification, consistent with CCAR (CCAR 2005) and international standards. International guidance reports developed by the International Organization for Standardization (ISO) and the European Union require third-party verification to address the need for consistency and a high level of confidence in calculating tonnes of GHG emissions.

In developing the verification requirements for this regulation, staff looked at existing programs, most notably the California Climate Action Registry and the United Kingdom Emissions Trading Scheme (UK ETS) (DEFRA 2003). The Californian Energy Commission (CEC) has played a large role in CCAR's third party verification program (CEC 2002, CEC 2003). CEC staff has pre-screened applicants to make sure they demonstrate basic educational and work skills to take CCAR verifier training and provide verification services in the voluntary program, and CEC continues to provide some oversight and guidance to CCAR on their verification program. Since CEC has provided this support and has developed guidance for verification and verifiers in the CCAR program, staff built on some of those principles for the mandatory reporting program.

In the development of the proposed ARB verification program staff consulted verifiers working in the CCAR and UK ETS programs. The International Emissions Trading Association and CEC staff provided helpful recommendations. Public comments were received through the course of technical discussions and mandatory reporting workshops during the spring and summer of 2007. Verification was discussed within each sector's technical team meetings as staff worked to understand specific sector needs and the nuances involved with a third party verification program.

B. Verification of Emissions Data

The core verification activities outlined in the regulation are developed from several existing GHG reporting programs and verification principles. In addition to CCAR's voluntary program, staff looked at key principles provided in ISO 14064-3 (ISO 2006a) and ISO 14065 (ISO 2006b), and the European Accreditation Guidance for Recognition of Verification Bodies under EU ETS Directive (EA 2005). Staff did not attempt to develop new requirements for verification activities, but pulled from existing programs

while trying to remain consistent with the guidance provided by the International Organization for Standardization.

There are several principles outlined in ISO guidance and accepted internationally as being the cornerstones of environmental data auditing for GHG reporting programs. These principles are completeness, consistency, comparability, accuracy, and transparency. ARB staff has worked to build these concepts into our proposed program, and we expect that the tangible products that result can be used to assess verifier performance, verification quality, and the quality of reported emissions data.

1. The Verification Cycle

The regulation calls for the annual verification of some emissions estimates and the triennial verification of others. When a reporting entity is required to have its emissions report annually verified, it has the option of having a full verification every three years and a less intensive verification in the interim years. This concept is similar to the verification cycle in CCAR's voluntary program. For example, in the first year, all of the verification requirements of a site visit, sampling plan, review of the data management system, and data checks would be required. In the second and third years, a verification effort may be reduced to emissions data checks based on the sampling plan developed in the first year. This cycle then repeats. Reporters subject to triennial verification must have a complete verification every third year, however.

In performing GHG emissions verification, there is a distinction between a verification body and a verification team. The verification body, a firm or an air district, has the liability for the verification services rendered and employs the lead verifier. The verification team is comprised of at least one lead verifier and several other verifiers (who may work for the verification body or be subcontractors) who actually provide the verification services specified in a contract between the verification body and the facility operator or retail provider. The lead verifier on the verification team renders services to a client, while the liability for those services lies with the verification body for which the lead verifier works.

2. Verification Activities

There are several key elements of verification as proposed in the regulation. The first is a mandatory site visit during the first year of verification. Site inspection allows the verification team to ensure that all required emission sources and processes within the defined facility boundaries are included in the emissions estimates and that the emissions report is as complete as required by the regulation. It is also an opportunity for the verifier to assess the adequacy of the data management and data acquisitions systems used to collect and process data underlying GHG emission estimates. At the same time, the verification team may conduct a review of contracts and other documents to substantiate reported data and ensure that data sampling and monitoring were conducted as applicable in the regulation.

The verification team is also required to develop a verification plan. This provides documentation of planned activities, site visits, and document reviews. This would be submitted by the verification body to ARB with a Notice of Verification Services, ten

days prior to a kick-off meeting with the reporting facility operator or retail provider. The Notice of Verification Services allows for ARB staff to plan in advance for any additional oversight of the verification with particular dates of verification activities proposed in advance.

A critical element of verification is the sampling plan. This plan is used to conduct data checks on the reported emissions. Verification does not call for a duplication of all emissions calculations, but rather checking specific subsets of the reported data based on several criteria. Selection of data subsets for checking involves a review of the largest contributions to overall emissions, as well as the emissions associated with the greatest uncertainties in estimation. To this end, the sampling plan includes a ranking of source contributions to overall emissions and a ranking of sources with the greatest emissions uncertainty.

The verification team conducts a qualitative risk assessment based on the uncertainty of the data acquisition equipment, data sampling and frequency, data processing, emissions calculations, data reporting, and management policies or practices applied to the emissions reports. For example, in evaluating the uncertainty of the data acquisition equipment, a verifier may check the age of a meter or the maintenance record for the meter. For data processing, the verifier may check how the data management system records and tracks data that supports emissions estimates; is it a simple spreadsheet with hand entered data used to track inputs for emissions calculations or direct readings from a data logger? The risk assessment qualitatively evaluates how much confidence rests with the underlying infrastructure that generates emissions estimates.

The regulation does not prescribe the number of data checks; the verification team exercises professional judgment in choosing these. Ultimately, however, the verification team must be able to state with reasonable assurance that the reported emissions are within 95 percent of the true CO_2e (CO_2 equivalent) emissions for the set of sources subject to reporting, and that all applicable regulatory methodologies and requirements have been met in the estimation and reporting of those emissions estimates. The accuracy level of 95 percent of CO_2e at the facility level is consistent with industry practice. Anything that results in an accuracy level less than 95 percent is considered a material error. If an emissions data report meets the materiality requirements of the regulation, then it means any errors found during verification do not cause a greater than 5 percent error in total CO_2e reported by the facility or retail provider.

During the course of the verification, the verification team is required to maintain an issues log of any findings that may affect materiality or conformance with the regulation. The team must also log how those issues are resolved to the satisfaction of the team so that the verification body may then provide a positive verification opinion. Any findings that result in a change of the initial data report submitted to ARB must be documented. This careful documentation provides transparency in the verification process and allows ARB to follow the verification in detail as part of its oversight role.

3. Completing the Verification Process

Upon completion of review by the verification team, the verification body submits a positive verification opinion to both the operator and ARB to indicate that verification team has found no material error in the emissions data report, and that the team finds the report meets the requirements of the regulation. Alternatively, the verification body submits a negative opinion indicating that the team has found material error or are otherwise unable to state that the emissions report meets the requirements of the regulation. When providing the verification opinion, the verification body will have an opportunity to add any comments or qualifiers they deem necessary to provide a complete context for the verification. The verification body also submits a detailed verification report to the reporting entity that includes the verification plan, sampling plan, issues log and additional documentation. The detailed verification report is retained by the reporting entity, but is made available to ARB upon request. The detailed verification report may be used by ARB at its discretion, to review the work of the verification body or review the verification process or the submitted data.

If a verification body and reporting entity cannot agree on the verifiability of the reported emissions or the need to revise the emissions data report, the reporting entity may petition ARB for review of the verification opinion. ARB could use any experts at its disposal to review questions, and both parties would be held to the subsequent ARB decision.

C. Accreditation of Verifiers

To assure the quality of verification services, staff has proposed rigorous accreditation requirements consistent with standards in CCAR and other existing programs, as well as ISO guidance. Both firms and individuals would be subject to specific requirements that include pre-screening and training under an ARB approved curriculum. To assure stability in the verification process, a company qualified to provide verification services would need to have at least five staff members, including two lead verifiers, and carry liability insurance. There are some variations in accreditation requirements for air pollution control districts, which as well established local government agencies provide assurance of stability.

The concept of a verification body having two lead verifiers comes from existing requirements in the European Union. It allows for internal independent review of verification reports and a final internal check that all verification activities and the detailed verification report meet standards in the regulation before being submitted to ARB. CCAR is considering a similar requirement.

1. Lead, General, and Sector Specific Verifiers

Since CCAR has lead verifiers that have passed CEC screening and taken CCAR lead verifier training, staff find it appropriate to have CCAR lead verifiers with demonstrated experience 'grandfathered' as lead verifiers into ARB's program. (The demonstrated experience means that they worked as project leads on three separate verifications under the CCAR program.)

Staff also recognizes the work and rigor required to become a United Kingdom Accreditation Service (UKAS) accredited verifier in the EU ETS program and proposes to add them to the pool of GHG lead verifiers. Since ISO guidelines were used extensively to develop the verification program, the proposal would also allow for individuals who have been accredited in data auditing or GHG emissions development or verification as directed by ISO to serve as lead verifiers. The proposal also recognizes that experience gained from leadership in developing GHG or other air emissions inventories, or experience gained as a technical lead in air emissions consultation, should meet pre-qualification requirements for serving as a lead verifier.

All individuals who meet the qualifications to lead a verification team would take ARB approved verification training and pass an exit exam. Staff has also proposed criteria that would allow for individuals that gain relevant project management experience to become leads in ARB's program. ARB has a goal of qualifying 75 lead verifiers by the time reporting begins in 2009.

In addition to general verifiers staff recognizes the need for sector specific verifiers for retail providers, refineries, and cement plants. These sectors have often complex process emissions, rigorous fuel test requirements, contractual arrangements and sales and purchase complexities that require verifiers to have special knowledge. ARB will offer sector specific training in addition to general verification and lead verifier training. All lead verifiers and general verifiers may take the additional sector specific training. Lead verifiers who lack experience in environmental or financial auditing would have additional training. Based on guidance from existing programs, these various requirements aim to ensure quality and consistency in the conduct of verification activities.

D. Conflict of Interest

The verification body and reporting facility operator or retail provider agree on a monetary payment for services rendered when they enter into a contract. As with any business relationship, there must be provisions to protect against conflict of interest. That safeguard is even more important when the verification services rendered may someday put value on the reported emissions. Not only is the verifier reviewing the amount of emissions reported, but they are also reviewing the reporting entity's conformance with the requirements of the regulation.

ARB wants to provide highly accurate GHG data to the public. This requires the verification process to be independent and free of any external bias creeping into the process of reviewing the reported emissions. CEC provided conflict of interest guidance to CCAR drawn from existing concepts in financial auditing and environmental programs. The conflict of interest policy in the regulation provides guidance and criteria as to what types of relationships and practices are unacceptable between a verification body and the reporting entity.

Prior to providing verification services to a reporting entity the verification body must evaluate the level of conflict between itself and the reporting entity. This evaluation will be reviewed by ARB. If the potential conflict is determined to be high, then verification may not commence between that verification body and the client. If potential conflict is found to be low, then ARB will approve the verification and the process will commence. If the ARB finds a medium level of risk of conflict of interest, ARB may request more information to improve its understanding of the relationship, and recommend steps to mitigate any conflict before finding the risk of acceptable and allowing the verification process to proceed.

A basic purpose of verification is to provide an independent level of review of the reported GHG emissions data. The conflict of interest policy strictly prohibits any verification body from acting as a consultant in estimating and reporting GHG emissions to ARB and then verifying those emissions. The regulation lists specific tasks that are in conflict with the principle of independent review. This concept is outlined in the CEC guidance to CCAR for the voluntary program and discussed in ISO guidance for GHG verification bodies.

The regulatory proposal requires changing verifiers after six years, consistent with CEC recommendations to avoid potential conflict of interest issues from lengthy business relationships. This results in a new set of eyes to review the emissions estimates provided by the reporting facility. Staff agrees this requirement will reduce complacency that may occur given the comfort and familiarity a verification body may feel toward a reporting facility after that time period. Verifier rotation is currently part of the CCAR voluntary program, and ARB has included such requirements in the proposed regulation.

V. ENVIRONMENTAL IMPACTS OF THE 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 the ARB's program for the adoption of regulations has been certified by the Secretary of Resources (Public Resources Code, Section 21080.5, Exemption of specified regulatory programs), the CEQA environmental analysis requirements are allowed to be 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, the 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 greenhouse gas (GHG) emissions by specified facilities to the Air Resources Board, and verification by third parties, and these activities produce no adverse environmental impacts. The collected data may be used by future programs to establish baseline GHG emissions, develop and track regulatory activities, and evaluate GHG emissions reductions.

B. 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, to 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 include mandatory reporting for over 90 percent of the stationary source GHG emissions in California, including specified combustion, process, and fugitive emissions. Emissions information from these reports will be made 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 workgroups, provided opportunities to participate in meetings by internet webcasting and phone, widely distributed all materials, and maintained consistent contact with interested community and environmental representatives. Staff also made a presentation to the Global Warming Environmental Justice Advisory Committee and discussed the development of the regulation with committee members on April 30, 2007.

VI. ECONOMIC IMPACTS OF THE REGULATION

The economic impacts analysis shown in this report was conducted to meet current legal requirements under the Administrative Procedure Act (APA).

In this chapter we provide the estimated costs to businesses and public agencies to comply with staff's proposed mandatory California greenhouse gas reporting requirements. The regulation will affect about 800 facilities and other reporting entities in the state. While staff has quantified economic impacts to the extent feasible, the cost estimates are based on limited survey information and general knowledge of emissions reporting and verification. This impacts analysis, therefore, serves to provide a general picture of the economic impacts that typical businesses subject to the proposed regulation might encounter. We recognize individual companies may experience different impacts than those projected here.

Overall, most affected businesses are among the larger businesses in California. We do not expect these businesses to be affected adversely by the costs of the proposed GHG reporting regulation. 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 significant adverse economic impacts to any local or State agencies.

A. Summary of Costs and Economic Impacts

Implementation of the mandatory greenhouse gas (GHG) reporting regulation for California has three primary costs: 1) GHG reporting costs, including both the preparation of an annual emissions report and, for some facilities, the purchase of new equipment and monitoring devices; 2) costs for third-party verification of submitted GHG emissions data as required; and, 3) costs to the State to administer the reporting program, including training, auditing, and compliance.

Staff has attempted to minimize costs while complying with the specific reporting requirements of the Act. The affected businesses and operations include electricity generating facilities, electricity retail providers, electric power marketers, oil refineries, hydrogen plants, cement plants, cogeneration facilities, and industrial sources that emit over 25,000 metric tonnes per year of CO_2 from stationary source combustion (e.g., facilities such as food processing, glass container manufacture, oil and gas production, and mineral processing). We estimate the total annual costs associated with meeting greenhouse gas reporting requirements to be in the range of $10 to $50 million per year during the first and second years for businesses, local, and state government, with a midpoint estimate of approximately $30 million. Of these overall reporting costs, we are anticipating costs to local agencies to be approximately $120,000 to $800,000 (with a midpoint of $460,000), and State reporting costs to be approximately $90,000 to $600,000 (with a midpoint of $345,000). Table VI-1 summarizes these estimates.

The third year and subsequent year costs for reporting facilities are anticipated to be in the range of $6 to $35 million annually statewide, with a midpoint estimate of approximately $21 million. The first and second year costs are higher due to the possible need for new equipment, sampling systems, training, and other start-up costs to meet the regulatory requirements. The ranges of the estimated costs are extremely wide because of the substantial variability in potential reporting and verification costs among facilities subject to the regulation. We anticipate costs to diminish over time as facilities incorporate GHG reporting into their normal business practices.

Table VI-1. First and Second Year Cost Breakdown by Classification

Facility Classificatior	Number of Reporters	Approximate Annual Costs
Private Business	~800	$9 to $49 million (midpoint $29M)
Local Agencies	~30-60	$120,000 to $800,000 (midpoint $460k)
State	~20-40	$90,000 to $600,000 (midpoint $345k)

GHG reporting as specified is mandatory for any facility or entity that meets the regulation's applicability requirements. Therefore, some public agencies could be subject to reporting, such as certain county or city owned sewage treatment works or landfills, local municipal utility districts or electric retail providers, some State universities, and other State facilities that emit more than 25,000 metric tonnes of CO_2 from stationary combustion sources. The Department of Water Resources is also expected to have a reporting requirement related to imported power. The cost estimate above includes costs to local government agencies and State agencies subject to the GHG reporting requirements. These local and state government agency reporting costs are anticipated to be less than $1 million per year statewide.

The local government agencies that could be subject to reporting include cities, counties, public utility districts, or others that maintain facilities such as certain landfills, certain sewage treatment plants, or publicly owned electricity providers.

The specific cost for a facility subject to GHG reporting will generally depend on the complexity of the facility. Complex facilities with a large number of processes or that require ongoing monitoring of variable fuel streams, such as refineries, will have higher costs that could range from $50,000 to over $300,000 per year. Simple facilities such as those with only natural gas fired boilers can use default emission factors to estimate their GHG emissions, and their costs will likely be in the $3,000 to $20,000 per year range. Medium complexity facilities such as cement manufacturing plants or cogeneration plants would likely have annual reporting and verification costs in the range of $7,000 to $50,000. The vast majority of facilities and entities subject to reporting (over 90 percent) will fall within the low and medium complexity categories.

Most businesses affected by the proposed regulation are the larger businesses in California, typically with millions of dollars in annual revenue. The cost of this proposed regulation is not expected to have a significant material impact on these businesses. As a result, we do not expect a noticeable change in employment, business creation, elimination or expansion, or business competitiveness in California due the reporting requirements.

No job or business losses are anticipated in California due to the reporting regulation. However, we are expecting a small increase in California employment for consultants who will assist facilities in meeting the regulatory requirements. These consultants will act as either technical assistance providers to assist in preparing emissions reports, or as verifiers, who will verify submitted emissions data for completeness and quality. Additional jobs may also become available at laboratories or facilities conducting fuel testing, or in the manufacture and installation of monitoring equipment. At full implementation, we estimate that approximately 40 to 75 new technical consulting jobs and 10-15 new businesses would be created within California.

All the cost estimates provided in this chapter are relative to the year 2007 (current value of the costs), and all costs are given in 2007 dollars. The information, assumptions and methodologies used to determine compliance costs are summarized in this chapter.

B. Legal Requirements for Fiscal Analysis

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.

Health and Safety Code 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 ten million dollars in any single year.

The following is a description of the methodology used to estimate costs, as well as ARB staff's analysis of the economic impact on California businesses and State and local agencies.

C. Analysis of Estimated Costs for Compliance

As part of developing the GHG reporting regulation we developed approximate cost estimates for facilities subject to the regulation. Briefly, the methodology for estimating costs for facilities and entities included:

- Collecting cost survey data from companies voluntarily reporting their GHG emissions and others potentially subject to mandatory reporting.
- Evaluating costs associated with preparing emissions reports, including the use of technical assistance providers, the need to possibly develop reporting systems, developing GHG emission estimates, providing staff to prepare and submit the emissions reports, and the maintenance and storage of records.
- Estimating costs for new measurement or monitoring equipment and systems directly needed to comply with the reporting requirements.
- Estimating the costs for reporting facilities to contract with third-party verifiers to confirm that the facilities performed their emission estimates in compliance with the GHG reporting regulation.
- Categorizing facilities based on the expected complexity of the emission estimates and developing cost ranges based on complexity and cost survey data.
- Applying the appropriate costs to each facility type and classification to develop overall cost ranges for program implementation.

In addition to estimating the costs for reporting facilities, we evaluate the costs to State and local government agencies to implement the proposed GHG reporting regulation.

In performing the cost analysis for the regulation we relied on estimated costs provided by those reporting their GHG emissions to the voluntary California Climate Action Registry, the estimated costs provided by those who may be subject to mandatory reporting regulation, and consultation with GHG verifiers and technical providers. ARB staff used this information and our professional judgment to develop cost ranges for facility classifications based on the complexity of the reporting facilities and entities, and the approximate number in each classification. For determining impacts on small business, we made an approximation of the number of affected facilities and their associated costs per facility. For State costs we estimated the costs to the ARB to implement the program as well as approximate costs for State facilities subject to the reporting requirements. Local costs were considered based on an estimate of the possible number of affected local facilities and their approximate costs.

Table VI-2, which follows, provides an approximation of estimated program-wide reporting costs. These cost ranges were developed based on the anticipated costs of reporting, verification, and any new equipment or systems needed to meet the reporting requirements. The first column provides a subjective assessment of facility or entity complexity as it relates to estimating GHG emissions or providing other information required by the regulation. For example, a low complexity facility might be a combustion source with just a couple of natural gas boilers, a medium complexity facility could be a

cement manufacturing plant, and a highly complex facility or entity would be a refinery or an electric retail provider. The columns in the table summarize estimated statewide first and second year costs, (which could include the installation of new equipment or systems, training, and other start up costs) and ongoing annual statewide reporting costs. These first and second year cost and ongoing cost columns are further subdivided into estimated low, high, and midpoint facility costs. These values are based on cost survey data and staff judgment.

As shown, there is tremendous variability in the range of estimated costs even within individual facility complexity classifications. This is because each facility that will be subject to reporting is unique, and individual reporting costs, even for the same types of facilities, could vary substantially based on the size and complexity of the facility, the presence of existing staffing and systems to assist with GHG reporting, and other factors. In addition, the exact number of affected facilities is not known in all cases. These factors make a precise estimate of overall reporting costs difficult.

In summary, the midpoint first and second year statewide costs to implement the regulation are estimated to be about $30 million[6] per year. The midpoint estimate for future years is about $21 million. These cost estimates include private businesses, as well as costs to local government and State agencies that would be subject to reporting their GHG emissions. Local government agencies that may be affected include some cities, counties, public utility agencies, municipal utility districts, and possibly others. Affected local government facilities include certain landfills, certain sewage treatment plants, public electricity utilities, and potentially others. State agencies affected would include certain universities and other State sources that emit 25,000 or more metric tonnes of CO_2 per year from stationary combustion sources.

Table VI-2. Approximate GHG Reporting Cost Ranges

Estimated Annual Statewide Cost Ranges

	Total First and Second Year Costs[1]			Total Ongoing Annual Costs[2]		
Facility/Entity Complexity	Low	High	Midpoint	Low	High	Midpoint
Low[3]	1,277,500	4,015,000	2,646,250	1,095,000	3,650,000	2,372,500
Medium[4]	2,382,000	17,865,000	10,123,500	1,985,000	15,880,000	8,932,500
High[5]	6,445,000	27,640,000	17,042,500	3,270,000	15,890,000	9,580,000
Totals	**10,104,500**	**49,520,000**	**29,812,250**	**6,350,000**	**35,420,000**	**20,885,000**

Table Notes:

[1]Cost includes annual reporting costs, verification costs, and any initial capital costs for reporting systems, monitoring equipment, training, and other start-up costs.

[2]Includes annual reporting and verification costs.

[6] Includes cost of $7 million (midpoint estimate) per year for first two years for refineries to install new monitoring equipment. Information provided by petroleum industry indicates refinery start-up costs could be higher than this staff estimate.

[3]Includes simple power generating facilities and facilities that emit ≥ 25,000 metric tonnes CO_2 from stationary combustion sources which are not part of other facility reporting such as natural gas transmission, industrial gases, paperboard manufacture, colleges and universities, oil production, food processing, steel foundries, mineral processes, glass container manufacture, malt beverages, some landfills, and some publicly owned treatment works.

[4]Includes cement plants, hydrogen plants, more complex power generating facilities, cogeneration facilities, and power marketers.

[5]Includes petroleum refineries and electricity retail providers.

D. Economic Impacts of 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.

The types of businesses that may be impacted by the proposed regulation include electricity generating facilities, electricity retail providers, electric power marketers, oil refineries, hydrogen plants, cement plants, cogeneration facilities, and industrial sources that emit over 25,000 metric tonnes per year of CO_2 from stationary source combustion (which includes facilities such as food processing, glass container manufacture, oil and gas production, and mineral processing).

Only the direct costs of complying with the reporting regulation are included in this analysis, which includes reporting and verification of facility GHG emissions or other required information.

1. Impacts to California Businesses

The proposed GHG reporting regulation focuses on the largest stationary sources of GHG emissions. Most of these stationary source GHG emissions are produced by private California business such as power plants, refineries, cement plants, and others, so these businesses will incur the majority of the GHG reporting costs. Some local government and state agencies will also incur costs.

The costs for typical businesses subject to the regulation vary widely. Facilities with only a small number or uncomplicated GHG emission sources (such as natural gas boilers) will have low costs. More complicated facilities or entities with many or complicated GHG emission sources (such as refineries or electricity retail providers) will have significantly higher costs. Based on the proposed reporting requirements, smaller or simpler facilities with potentially lower revenues will have relatively low reporting costs. Larger or more complex facilities, with typically higher revenues, will generally incur higher costs to estimate their GHG emissions. With this graduated approach, we

believe that facilities subject to these regulations will be able to readily absorb the costs of compliance without a significant impact on profitability or competitiveness.

The specific cost for a facility subject to GHG reporting will generally depend on the complexity of the facility. Complex facilities with a large number of processes or which that require ongoing monitoring of fuels, such as refineries, will have higher costs which could range from $50,000 to over $300,000 per year. Simple facilities, such as those with only a couple of natural gas fired boilers, can use default emission factors to estimate their GHG emissions, and their costs will likely be in the $3,000 to $20,000 per year range. We expect that the majority of facilities to fall into this cost range. ARB staff is not aware of any business that exists in California that could fall into the category where the fiscal impacts of GHG reporting are significant compared to their revenues. However, the regulation could theoretically impose hardship on some businesses that are operating with little or no margin of profitability.

Because there are facility start-up costs to develop GHG reporting systems, develop facility expertise, install any new equipment, and attend and provide personnel training, we anticipate industry costs to decline over time as GHG reporting becomes incorporated into standard facility practices.

2. Impacts to Small Businesses[7]

We do not have an exact estimate of the number of small business affected by the regulation. For this analysis we have assumed that approximately 30 to 60 small businesses may be affected. We developed this estimate using the following approach. First we assumed that 200 facilities would be required to report because they meet applicability as facilities that emit 25,000 metric tonnes or more of CO_2 from stationary combustion sources. From a review of the types of businesses on this list, we assumed that 15-25 percent of these 200 facilities might be small businesses, and then assumed that there could be another 10 small businesses in other reporting sectors. This approach was used to develop the estimate that 30 to 60 small businesses could be required to report their GHG emissions. This is a conservative estimate, meaning that realistically, the number of small businesses affected is anticipated to be in the lower range of the estimate.

Based on the types of small business expected to be impacted and the kinds of GHG generating activities present at these facilities, we expect reporting costs for small businesses to be low. From survey data, we anticipate costs to individual small business to be in the range of $3,000 to $15,000 per year. However, in our survey data, we did not receive any responses from small businesses, so this is a staff approximation based on our evaluation of the types of processes expected at small

[7] 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)

businesses and their potential reporting costs relative to other survey data received. ARB staff is not aware of any small business that exists in California that could fall into the category where the fiscal impacts of GHG reporting are significant. However, the regulation could theoretically impose hardship on some small businesses that are operating with little or no margin of profitability.

3. Impacts to California State and Local Agencies

We have estimated overall State and local agency costs to report and verify their GHG emissions to be approximately $800,000 per year. The local government and agencies that could be subject to reporting include some cities, counties, public utility districts, or agencies that maintain facilities such as certain landfills, certain sewage treatment plants, or publicly owned electricity providers. Local government GHG reporting costs were roughly estimated to be approximately $460,000, with a potential range of $120,000 to $800,000. This estimate is based on an estimate that there may be 40 local facilities subject to reporting, with a per facility cost range of $3,000 to $20,000. However, because we do not yet have complete information on the number of local government facilities affected and their specific costs, this exercise can only provide a sense of the potential costs to affected local agencies.

Using similar assumptions, we estimated that total reporting costs for State facilities could be approximately $345,000, with a range of $90,000 to $600,000, based on an assumption of 30 state facilities. This could include facilities such as some universities, prisons, or other State sources that emit over 25,000 metric tonnes of CO_2 from stationary combustion or are required to report electric power imports. Again, there is uncertainty with this estimate due to incomplete information on the number of affected State facilities and their reporting costs. Information acquired to date, from air pollution control districts, indicates the number of state facilities with emissions above the regulation's reporting thresholds is likely to be small.

Based on these estimates we do not find GHG reporting costs for State or local agencies to be significant, and believe that the costs can be absorbed within existing operating budgets. The reporting costs for these State and local facilities will generally be proportional to the size and complexity of the facility, which will typically be related to their operating budgets and their ability to provide funding to meet the reporting requirements. Because the GHG reporting requirements are the same, reporting costs for individual State and local government agencies will be in the same ranges as those for private businesses and small businesses.

An additional State cost is incurred by the ARB to administer the reporting program. These costs include start-up costs to develop reporting tools and training materials (approximately $600,000), as well as annual costs for new staff to implement the reporting and verification program (approximately $935,000) and maintain the reporting tool (approximately $50,000). In summary, the initial ARB start-up costs are roughly $600,000, with annual ARB operational costs of approximately $1 million to administer the program.

4. Potential Impact on Consumers

No noticeable change in consumer prices is expected from the reporting regulation because the compliance costs will have only a minor impact on the affected businesses.

5. Impact on Employment

Since the compliance costs associated with the GHG reporting regulation impose only a very small impact on California businesses, the staff expects no significant change in employment due to the imposition of the compliance costs. However, the regulation could theoretically impose hardship on some businesses operating with little or no margin of profitability, affecting the creation or elimination of jobs in California.

Staff has determined that the proposed regulation will create jobs in California. These jobs will be in the fields of technical consulting needed to assist affected businesses in preparing their GHG emission reports and for the verification of those reports. It is estimated that 40 to 75 new California jobs could be created to provide these services. This estimate is based on the expected number of GHG reports to be submitted and the estimated number of verifiers and technical support providers needed to assist with those activities. Because some of the GHG reporting and verification work done by consultants will be done by existing firms and employees, and some of the work will be performed by firms outside of California, precise estimates of the number of jobs created are not possible.

6. Impact on Business Creation, Elimination, or Expansion

No change is expected to occur in the status of California businesses as a result of the reporting regulation. This is because the proposed regulation is expected to impose a minor cost on businesses in California. However, should the regulation impose significant hardship on California businesses operating with little or no margin of profitability, some small businesses may be forced out of the market or decide not to expand in California. Also, in theory some businesses could possibly decide against coming to California to avoid having to report their GHG emissions.

We have also estimated that 10 to 15 new California companies could be created as a result of the regulatory action. This is based on an estimate of the total number of verifiers and technical provider firms likely needed, the number of these firms that might be new businesses, and the number of firms that might be based within California. This number is also approximate because existing firms will likely attempt to absorb as much of the new workload as possible, and the amount of spill-over available to new companies cannot be clearly determined.

7. Impacts to California Business Competitiveness

The regulation would have little or no impact on the ability of California businesses to compete with businesses in other states. This is because the regulation does not impose a significant cost impact on California businesses. In addition, many of the businesses affected by the regulation are local businesses serving California clients, and may not be strongly subject to intrastate competition. However, the proposed

regulation could have an adverse impact on the ability of some California businesses, operating with little or no margin of profitability, to compete with businesses in other states.

VII. ALTERNATIVES TO THE PROPOSED REGULATION

ARB staff did not find any of the alternatives considered to be more effective in carrying out the purpose for which the regulation is intended, or to be as effective or justifiably less burdensome to affected private persons, than the proposed regulation. The staff evaluated various alternatives to the current proposal. A description of the alternatives considered and staff's rationale for finding them unsuitable follows below.

Take No Action

ARB is required under the Act to adopt a regulation by January 1, 2008, requiring mandatory reporting of greenhouse gases in California, so taking no action is not allowable under State law.

Include More Facilities in Reporting Requirements.

Staff could have extended reporting requirements to additional facilities. As explained in this report, a lower threshold for general stationary sources was considered but found to provide little additional short-term value for the reporting burden imposed. Additional sectors could have been added, but at the risk of not completing sound reporting methods for any sector due to spreading available resources too thinly. We focused on several key sectors to gain emissions reports from 94 percent of the State's point source emissions, already a challenging goal in the one year available to complete the regulation development process.

Include Fewer Facilities in Reporting Requirements

Refineries, cement manufacturers, and the electric power sector are among the largest sources of CO_2 from stationary combustion in the State, and the latter two already had reporting protocols in the voluntary program that could be used to develop mandatory reporting methodologies. Cogeneration facilities and hydrogen plants are significant supplemental sources with important roles to play both for understanding GHG emissions and reducing them. Staff chose the 25,000 metric tonne CO_2 threshold to capture additional stationary combustion facilities that are not included in the other sectors and develop a comprehensive picture of large stationary CO_2 sources in the State. In general the large industrial sources at this threshold are significant GHG contributors that have the means to incorporate GHG reporting into their environmental procedures. Staff has thus found no reasonable justification to exclude any of the sources that would be subject to reporting under the proposed regulation.

Require a More Comprehensive Verification Process

It is possible to add more stringency to the verification process. For example, instead of a qualitative discussion of uncertainty in emission sources, the regulation could have called for a quantitative analysis of estimation uncertainty. Staff did not see the added value of increasing verification requirements and recognized that a resource problem could result for verification bodies and ARB in its oversight process. This would make it

harder for reporting facilities and verification bodies to meet verification deadlines. The current level of rigor is appropriate for ensuring data accuracy, providing ARB with information as part of its oversight process, and developing a reporting program consistent with existing GHG reporting programs.

Require a Less Comprehensive Verification Process

The verification requirements in the regulation constitute a program that will ensure data accuracy and oversight of emissions reporting. To allow any less stringency in the verification process would diminish data accuracy, risk compromise of data through economic conflict of interest, limit ARB's ability to oversee the reporting process, and result in a GHG reporting program that has less stringency than comparable existing programs in the European Union and California's voluntary program.

Allow Self-Verification of Emissions Reports

Staff considered the recommendation of several stakeholders to allow the higher level personnel at affected facilities to self-verify the emissions reports. The stakeholders argued that company chief executive or operating officers would sign the reports and face penalties of perjury for misstatement. Staff rejected this option because most emission reports submitted voluntarily have been found by independent verifiers to contain errors and factual misstatements, often unintended, that the signatories did not and cannot be expected to have discovered. Our interest is not in assessing fines or threatening jail time for misstatements, but in getting accurate emissions reports. Trained, experienced, independent verifiers provide the dispassionate expertise to help assure the accuracy expected by international standards.

Have Air Districts Provide All Third Party Verification Services

ARB welcomes the participation of districts to help assure an adequate number of verifiers, and several districts have expressed interest in participating in the verification program. However, the sole use of air districts as verification bodies was determined to be infeasible, since the districts alone cannot be assured to have sufficient resources to meet the rigorous deadlines prescribed in the regulation given the number of emissions data reports that will be subject to verification. Stakeholders have expressed much concern about sufficient verifier availability, and ARB staff estimates at least 150 individuals will need to be involved in verification services statewide. Nonetheless, the verification requirements of the regulation are designed to be inclusive of air districts desiring to become verification bodies. Interested and committed districts that demonstrate they meet the requirements to become verification bodies may offer their verification services alongside private third-party verifiers for a service fee.

Staff also recognizes the desire to be consistent with the emerging national Climate Registry in considering the question of air districts as sole verifiers. Most Registry member states do not have air districts and all air quality issues are handled at the state level. Since California's GHG mandatory reporting program may interact on a national

and international level, staff wants to ensure a level of consistency among states in the verification program.

Several affected facilities have expressed a preference for air districts as verifiers of their emissions reports, since the districts are already familiar with their sources and already trusted with confidential information; others have been clear they prefer to use private firms.

Use ARB Staff for Verification

Before proposing independent third-party verifiers, staff explored the use of ARB staff as verifiers. The State would need to add numerous staff and resources to be able to effectively verify the hundreds of submitted emissions reports. Staff estimated that over 150 dedicated positions would be needed to spend the time required for site visits to examine sources, draw up sampling plans and risk assessments, check emissions calculations, and develop and issue verification reports and opinions. Through use of third-party verifiers, including the experts already working in the field of GHG emissions verification, California is able to remain consistent with existing GHG reporting programs and assure data quality, while creating opportunities for highly skilled positions at air districts and in the private sector. Under the staff proposal ARB will provide training and oversight of the verifiers, and carry out audits to assure a consistent, fair and robust verification process.

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ATTACHMENT A

Proposed Regulation Order

REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

Proposed Regulation Order

REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

Adopt new Subchapter 10, Article 1, sections 95100 to 95133, title 17, California Code of Regulations, to read as follows:

Subchapter 10: Climate Change

This subchapter contains regulations to implement the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)

Article 1: Mandatory Greenhouse Gas Emissions Reporting

95100. Purpose.

The purpose of this article is to require the reporting and verification of greenhouse gas emissions from greenhouse gas emissions sources in California. This article is designed to meet the requirements of section 38530 of the Health and Safety Code.

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95101. Applicability.

(a) ***Organization of this article.*** Subarticle 1 specifies general requirements for the reporting of greenhouse gas emissions that apply to all facilities listed below in section (b). Subarticle 2 specifies reporting requirements and calculation methods for specific types of facilities. Subarticle 3 specifies calculation methods that are applicable to multiple types of facilities. Subarticle 4 specifies greenhouse gas emissions report verification requirements and the requirements for those who perform greenhouse gas emission verifications.

(b) Except as provided in section 95101(c), this article applies to the following entities conducting business in California:

(1) Operators of cement plants;
(2) Operators of petroleum refineries;
(3) Operators of hydrogen plants that emit greater than or equal to 25,000 metric tonnes of CO_2 from the combination of stationary combustion sources and hydrogen production processes in the report year;
(4) Operators of electric generating facilities (except as provided in section 95101(c)) with a nameplate generating capacity greater than or equal to 1 megawatt (MW) that emit at least 2,500 metric tonnes or more of CO_2 in the report year from electricity generating activities, including hybrid generating facilities;
(5) Retail providers as defined in section 95102(a);
(6) Marketers as defined in section 95102(a);
(7) Operators of cogeneration facilities with a nameplate generating capacity greater than or equal to 1 megawatt (MW) that emit at least 2,500 metric tonnes or more of CO_2 in the report year from electricity generating activities, including cogeneration facilities that are within the operational control of other operators subject to the requirements of this article;
(8) Operators of other facilities that emit greater than or equal to 25,000 metric tonnes per year of CO_2 from stationary combustion sources in a report year.

(c) This article does not apply to:

(1) Electric generating facilities that are solely powered by nuclear, hydroelectric, wind, or solar energy;
(2) Portable equipment or electricity generators designated as backup generators in a permit issued by an air pollution control district or air quality management district;
(3) Hospitals with a North American Industry Classification System (NAICS) code starting with 62;
(4) Primary and secondary schools with a NAICS code of 611110.

(d) The Executive Officer may request a demonstration from any operator that a specified facility does not meet one or more of the applicability criteria specified in section 95101(b). Such demonstration shall be provided to the Executive Officer within 20 days of a written request received from the Executive Officer.

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 1. General Requirements for the Mandatory Reporting of Greenhouse Gas Emissions

95102. Definitions.

(a) For the purposes of this article, the following definitions shall apply:

(1) "Accredited verifier" means an individual approved by the ARB to provide verification services for those subject to reporting.

(2) "Adverse verification opinion" means the final opinion rendered by a verification body stating that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement and/or does not conform with the requirements of the regulation, and that all verification services have been completed by the verification team.

(3) "Annual" means a period of time covering a calendar year from January 1 through December 31.

(4) "API" means the American Petroleum Institute.

(5) "AQMD/APCD" means air quality management district or air pollution control district, as applicable to the facility location.

(6) "ARB" means the California Air Resources Board.

(7) "Asphalt" means a dark brown or black cementitious material (solid or liquid) of which the main constituents are bitumins which occur naturally or as a residue of petroleum refining.

(8) "Asphalt blowing" means the process by which air is blown through asphalt flux to change the softening point and penetration rate.

(9) "Asset controlling supplier" means any entity that operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them.

(10) "Asset owning supplier" means any entity owning electricity generating facilities that delivers electricity to a transmission or distribution line.

(11) "Associated gas" means a natural gas which is found in association with crude oil either dissolved in the oil or as a cap of free gas above the oil.

(12) "Barrel" means a volume equal to 42 U.S. gallons.

(13) "Best available data and methods" means ARB methods for emissions calculations defined in this article where reasonably feasible; or facility fuel use and other facility process data used in conjunction with ARB provided emission factors and other data; or other generally accepted methods for calculating greenhouse gas emissions.

(14) "Biomass" means non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms, including products, byproducts, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.

(15) "Biomass-derived fuels" or "biomass fuels" means fuels derived from biomass.

(16) "Bottom ash" means ash that collects at the bottom of a combustion chamber.

(17) "Bottoming cycle plant" means a cogeneration facility in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for power production.

(18) "British Thermal Unit (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.

(19) "Busbar" means the power conduit of an electric generating facility that serves as the starting point for the electric transmission system.

(20) "Butane" (C_4H_{10}) means a normally gaseous straight-chain or branch chain hydrocarbon extracted from natural gas or refinery fuel gas streams. It includes normal butane and refinery-grade butane.

(21) "Bypass dust" means discarded dust from the bypass system dedusting unit of suspension preheater, precalciner and grate preheater kilns, consisting of fully calcined kiln feed material.

(22) "CAISO integrated forward market" is the electric power market conducted by the California Independent System Operator that determines the best use of resources available while finding the least cost method of procuring required components.

(23) "CAISO markets" mean the California Independent System Operator's real-time market and the day-ahead integrated forward market.

(24) "CAISO real-time market" means the electric power market conducted by the California Independent System Operator where supplemental electric power is quickly bought or sold every ten minutes to accommodate power use just moments before it occurs.

(25) "Calcination" means the thermal decomposition of carbonate minerals, such as calcium carbonate (the principal mineral in limestone) to form calcium oxide in a cement kiln.

(26) "Calcine" means to heat a substance so that it oxidizes or reduces.

(27) "Calendar year" means the time period from January 1 through December 31.

(28) "California Climate Action Registry" means the entity established pursuant to Health and Safety Code Section 42900 et seq.

(29) "California eligible renewable resource" means an electric generating facility that the California Energy Commission has certified as an eligible renewable energy resource that may be used by a retail seller of electricity to satisfy its California Renewables Portfolio Standard Program procurement requirements, consistent with Public Utilities Code Sections 399.11 through 399.16 and Public Resources Code Sections 25740 through 25751.

(30) "Capacity factor" means the amount of energy that an electric generating facility actually generates compared to its maximum rated output over a given period of time, usually one year.

(31) "Carbon dioxide (CO_2)" means the most common of the six primary greenhouse gases, consisting of a single carbon atom and two oxygen atoms.

(32) "Catalyst" means a substance added to a chemical reaction, which facilitates or causes the reaction, and is not consumed by the reaction.

(33) "Catalyst coke" means carbon that is deposited on a catalyst, thus deactivating the catalyst.

(34) "Catalytic cracking" means a refinery process of breaking down larger, heavier, and more complex hydrocarbon molecules onto simpler and

lighter molecules. Catalytic cracking is accomplished by the use of a catalytic agent.

(35) "Catalytic reforming" means a refining process using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules.

(36) "Cement" means a building material that is produced by heating mixtures of limestone and other minerals or additives at high temperatures in a rotary kiln to form clinker, followed by cooling and grinding with blended additives. Finished cement is a powder used with water, sand and gravel to make concrete and mortar.

(37) "Cementitious product" means cement, cement kiln dust, cement clinker, clinker dust, fly ash, slag, and other pozzolans.

(38) "Cement kiln dust (CKD)" means the fine-grained, solid, highly alkaline waste removed from cement kiln exhaust gas by air pollution control devices, consisting of partly calcined kiln feed material. "CKD" includes all dust from cement kilns and bypass systems including bottom ash and bypass dust.

(39) "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.

(40) "Coal" means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–92 "Standard Classification of Coals by Rank" (as incorporated by reference in §72.13).

(41) "Coal-derived fuel" means any fuel, whether in a solid, liquid, or gaseous state, produced by the mechanical, thermal, or chemical processing of coal (e.g., pulverized coal, coal refuse, liquefied or gasified coal, washed coal, chemically cleaned coal, coal-oil mixtures, and coke).

(42) "Cogeneration facility," means an industrial structure, installation, plant, building, or self-generating facility that has sequential generation of multiple forms of useful energy (usually mechanical and thermal) in a single, integrated system.

(43) "Cogeneration system," means the individual components – prime mover (heat engine), generator, heat recovery, and electrical interconnection configured into an integrated whole.

(44) "Coke (petroleum)" means a solid residue consisting mainly of carbon which results from the cracking of petroleum hydrocarbons in processes such as coking and fluid coking. This includes catalyst coke deposited on a catalyst during the refining process which must be burned off in order to regenerate the catalyst.

(45) "Coke burn-off" means the coke removed from the surface of a catalyst by combustion in the catalyst regenerator.

(46) "Combustion emissions" means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

(47) "Combustion source" means a stationary fuel fired boiler, turbine, or internal combustion engine.

(48) "Conflict of interest" means a situation in which, because of other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification opinion of a potential client's greenhouse gas emissions, or the person or body's objectivity in performing verification services is or might be otherwise compromised.

(49) "Continuous emissions monitoring system (CEMS)" means the total equipment required to determine a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

(50) "Conveying system" means a device for transporting materials from one piece of equipment or location to another location within a facility. Conveying systems include but are not limited to the following: feeders, belt conveyors, bucket elevators and pneumatic systems.

(51) "Cracking" means the process of breaking down larger molecules into smaller molecules, utilizing catalysts and/or elevated temperatures and pressures.

(52) "Crude oil" means a mixture of hydrocarbons that exists in the liquid phase which is found in natural underground reservoirs.

(53) "Delayed coking" means a process by which heavier crude oil fractions are thermally decomposed under conditions of elevated temperature and pressure to produce a mixture of lighter oils and petroleum coke.

(54) "De minimis" means those emissions reported for a source or sources that are calculated using alternatives methods selected by the operator, subject to the limits specified in section 95103(a)(6).

(55) "Diesel fuel" means a fuel composed of distillates obtained in petroleum refining operation or blends of such distillates with residual oil.

(56) "Direct emissions" means greenhouse gas emissions from applicable greenhouse gas emitting sources that are under the operational control of the operator.

(57) "Distillate fuel oil" means a general classification for a petroleum fraction produced in conventional distillation operations. It includes diesel fuels and fuel oils.

(58) "Distributed emissions" means CO_2 emissions from fuel combustion at cogeneration facilities distributed between energy stream outputs including thermal energy, electricity generation and, where applicable, other product outputs.

(59) "District heating and cooling" means the distribution of heat or cooling from one or more sources to multiple buildings.

(60) "Electric generating facility" means generating facility.

(61) "Electricity transaction" means the purchase, sale, import, export or exchange of electric power.

(62) "Emission factor" means a unique value for determining an amount of a greenhouse gas emitted for a given quantity of activity data (e.g., million metric tonnes of carbon dioxide emitted per barrel of fossil fuel burned.).

(63) "Emissions" means the release of gases into the atmosphere from sources and processes in a facility.

(64) "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 this article.

(65) "Entity" means a company, corporation, nonprofit organization, government agency or other legally constituted body that has operational control over one or more facilities.

(66) "Equipment" means any stationary article, machine, or other contrivance, or combination thereof, which may cause the issuance or control the issuance of air contaminants; equipment shall not mean portable equipment, tactical support equipment, or electricity generators designated as backup generators in a permit issued by an air pollution control district or air quality management district.

(67) "Ethane" (C_2H_6) means a normally gaseous straight-chained hydrocarbon that boils at a temperature of -127.48 degrees Fahrenheit.

(68) "Exchange agreement" means a commitment between electricity market participants to swap energy for energy. Exchange transactions do not involve transfers of payment or receipts of money for the full market value of the energy being exchanged, but may include payment for net differences due to market price differences between the two parts of the transaction or to settle minor imbalances.

(69) "Executive Officer" means the Executive Officer of the ARB or his or her delegate.

(70) "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 gas and is considered a single major industrial grouping as identified by first two digits of the North American Industry Classification System (NAICS). Under this definition, those in operational control of military installations may classify military installations as more than a single facility based on independent functional groupings within contiguous military properties.

(71) "Feed" means the prepared and mixed materials, which include but are not limited to materials such as limestone, clay, shale, sand, iron ore, mill scale, cement kiln dust and fly ash that are fed to the kiln. Feed does not include the fuels used in the kiln to produce heat to form the clinker product.

(72) "Feedstock" means the raw material supplied to a process.

(73) "Flare" means a combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.

(74) "Flexicoking" means a thermal cracking process which converts heavy hydrocarbons such as crude oil, tar sands bitumen, and distillation residues into light hydrocarbons.

(75) "Fluid catalytic cracking unit (FCCU)" means a process unit in a refinery in which petroleum derivative feedstock is charged and fractured into smaller molecules in the presence of a catalyst; or reacts with a contact material to improve feedstock quality for additional processing; and the catalyst or contact material is regenerated by burning off coke and other deposits.

The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat.

(76) "Fluid catalytic cracking unit regenerator" means the portion of the fluid catalytic cracking unit in which coke burn-off and catalyst regeneration occurs, and includes the regenerator combustion air blower(s).

(77) "Fluid coking" means a thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products.

(78) "Fly ash" means particles of ash, such as particulate matter which may also have metals attached to them that are carried up the stack of a combustion unit with gases during combustion.

(79) "Fossil fuel" means a fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals.

(80) "Fuel" means solid, liquid or gaseous combustible material.

(81) "Fuel analytical data" means any data collected about the mass, volume, flow rate, heat content, or carbon content of a fuel.

(82) "Fugitive emissions" means the unintended or incidental emissions of greenhouse gases from the transmission, processing, or transportation of fossil fuels or other materials, such as HFCs from refrigeration leaks, SF_6 from electric power distribution equipment, methane from mined coal, and also includes CO_2 emitted incidentally with geyser steam and/or fluid used in geothermal generating facilities.

(83) "Full verification" means all verification services as provided in section 95131.

(84) "General stationary combustion facility" means a facility not otherwise subject to sector-specific reporting requirements that emits $\geq$25,000 metric tonnes of CO_2 in 2008 or any subsequent year from stationary combustion sources.

(85) "Generating facility" means a facility that generates electricity and includes one or more generating units at the same location.

(86) "Generating unit" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

(87) "Greenhouse gas or GHG" (GHG) means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), or perfluorocarbons (PFCs).

(88) "Greenhouse gas source" means any physical unit or process that releases a greenhouse gas into the atmosphere.

(89) "Gross generation" means the total electrical output of the generating unit, expressed in megawatt hours (MWh) per year.

(90) "Global warming potential (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.

(91) "Hydrocarbons" means chemical compounds containing predominantly carbon and hydrogen, including fossil fuels and a variety of major air pollutants.

(92) "Hydrofluorocarbons (HFCs)" means a class of GHGs primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

(93) "Hydrogen" means the lightest of all gases, occurring chiefly in combination with oxygen in water; exists also in acids, bases, alcohols, petroleum, and other hydrocarbons.

(94) "Hydrogen plant" means a facility that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.

(95) "High heat value (HHV)" means the high or gross heat content of the fuel with the heat of vaporization included. The water vapor is assumed to be in a liquid state.

(96) "Indirect energy" means electricity, thermal, or other energy sources provided by a retail provider or facility not owned or operated by the user of the energy.

(97) "Kerosene" means a light distillate fuel having a maximum distillation temperature of 400 degrees Fahrenheit at the 10% recovery point, a final boiling point of 572 degrees Fahrenheit and a minimum flash point of 100 degrees Fahrenheit. "Kerosene" includes No. 1-K and No. 2-K as well as other grades of kerosene called range or stove oil which have properties similar to those of No. 1 fuel oil

(98) "Kiln" means a device, including any associated preheater or precalciner devices that produce clinker by heating limestone and other materials for subsequent production of Portland cement.

(99) "Kilowatt hour (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.).

(100) "Less intensive verification" means the verification services provided in interim years between full verifications that only require data checks on a operator's emissions data report based on the most current sampling plan developed as part of the most current full verification services.

(101) "Liquefied petroleum gas (LPG)" means a petroleum hydrocarbon mixture containing propane, propene, butane, butene, and isobutane as its main components and is normally a gas but which can be compressed and condensed to a liquid.

(102) "Marketer" means a purchasing/selling entity that is not a retail provider, and that is listed as a purchasing/selling entity at the first point of delivery in California for electric power imported into California, or the last point of receipt for power exported from California. A marketer is an operator delivering power to the first point of delivery inside California for imports or delivering power to the first point of delivery outside California for exports.

(103) "Material misstatement" means an error or errors discovered in the course of verification that result in the total reported emissions, or reported purchases, sales, imports or exports of electricity, being outside the 95 percent accuracy required to receive a positive verification opinion.

(104) "Methane (CH_4)" means a GHG consisting of a single carbon atom and four hydrogen atoms.

(105) "Metric tonne" (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.

(106) "MMBtu" means million British thermal units.

(107) "Mobile combustion" means emissions from the transportation of materials, products, waste, and employees resulting from the combustion of fuels in company owned or controlled mobile combustion sources (e.g., cars, trucks, buses, trains, airplanes, ships, etc.).

(108) "Motor gasoline" means a complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines. Motor gasoline is characterized as having a boiling range of 122 to 158 degrees Fahrenheit at the 10-percent recovery point to 365 to 374 degrees Fahrenheit at the 90-percent recovery point.

(109) "Multi-jurisdictional utility" means a distribution utility that provides electricity to end users in California and in one or more other states.

(110) "NAICS" means North American Industry Classification System.

(111) "Nameplate generating capacity" means the rated continuous load-carrying ability expressed in megawatts (MW). Also, the maximum rated output of a generator under specific conditions designated by the manufacturer.

(112) "Naphtha" means a generic term applied to a petroleum fraction with an approximate boiling range between 122 degrees Fahrenheit and 400 degrees Fahrenheit.

(113) "Natural gas" means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions.

(114) "Net generation" means the gross generation minus station service or unit service power requirements, expressed in megawatt hours (MWh). In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

(115) "NERC E-tag" means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow within, between, or across electric utility company territories.

(116) "No. 1 diesel fuel" means a light distillate that has a distillation temperature of 55 degrees Fahrenheit at the 10-percent recovery point and 550 degrees Fahrenheit at the 90-percent recovery point.

(117) "No. 1 distillate" means a petroleum distillate that can be used as either a diesel fuel or a fuel oil.

(118) "No.1 fuel oil" means a light petroleum distillate fuel having a maximum distillation temperature of 190 degrees Celsius at the 10% recovery point and 275 degrees Celsius at the 90% recovery point.

(119) "No. 2 diesel fuel" means a distillate fuel that has a distillation temperature of 640 degrees Fahrenheit at the 90-percent recovery point.

(120) "No. 2 distillate" means a petroleum distillate that can be used as either a diesel fuel or a fuel.

(121) "No.2 fuel oil (heating oil)" means a distillate fuel oil that has distillation temperatures of 640 degrees Fahrenheit at the 90% recovery point.

(122) "No. 4 fuel" means a distillate fuel oil made by blending distillate fuel oil and residual fuel oil stocks.

(123) "Nitrous oxide (N_2O)" means a GHG consisting of two nitrogen atoms and a single oxygen atom.

(124) "Nonconformance" means the failure to use the methods or emission factors specified in the regulation to calculate emissions, or to meet other requirements of the regulation.

(125) "North American Industry Classification System" 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.

(126) "Null power" means any electricity produced by a renewable energy electric generating facility from which a Western Renewable Energy Generation Information System (WREGIS) certificate has been unbundled and sold separately.

(127) "Operator" means the company or organization having operational control of a facility or entity for which an emissions data report is required. For purposes of reporting electricity transactions as required in section 95111, "operator" means the company or organization that is the retail provider or marketer.

(128) "Operational control" for a facility subject to this article means the authority to introduce and implement operating, environmental, health and safety policies. In any circumstance where this authority is shared among multiple parties, the party holding the permit to operate from the local air pollution control district or air quality management district is considered to have operational control for purposes of submitting the emissions data report.

(129) "Pacific Northwest" means Washington, Oregon, Idaho, Montana, and British Columbia.

(130) "Perfluorocarbons (PFCs)" means a class of greenhouse gases consisting of containing carbon and fluorine.

(131) "Petroleum" means oil removed from the earth and the oil derived from tar sands, shale and coal.

(132) "Petroleum coke" means a residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking.

(133) "Petroleum refinery" means any facility engaged in producing gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

(134) "Point of delivery" means a point on an electric system where a power supplier delivers electricity to the receiver of that energy. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

(135) "Point of receipt" means a point on an electric system where an entity receives electricity from a supplier. This point can be an interconnection with another system or a generator busbar.

(136) "Point source" means any separately identifiable stationary point from which greenhouse gases are emitted.

(137) "Portable" is as defined in title 17, California Code of Regulations, Section 93116.2(bb).

(138) "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.

(139) "Positive verification opinion" means the final opinion rendered by a verification body stating that the verification body can say with reasonable assurance that the submitted emissions data report is free of material

misstatement and conforms with the requirements of this article, and that all verification services have been completed by the verification team.

(140) "Power contract" means an arrangement for the purchase of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.

(141) "Pressure swing adsorption (PSA)" means a gas purification process which selectively concentrates target gas molecules using porous, high surface area solid adsorbents and elevated pressure.

(142) "PSA off-gas or tail-gas" means the impurity stream resulting from the sequential PSA pressurization/depressurization purification process.

(143) "Prime mover" means the type of equipment such as an engine or water wheel that drives an electric generator. "Prime movers" include, but are not limited to reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

(144) "Process emissions" means greenhouse gas emissions other than combustion emissions occurring as a result of intentional and unintentional reactions between substances or their transformation, including the chemical or electrolytic reduction of metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

(145) "Process gas" means any gas generated by an industrial process such as petroleum refining.

(146) "Process vent" means an opening where a gas stream is continuously or periodically discharged during normal operation. Process vents include openings where gas streams are discharged to the atmosphere directly or are discharged to the atmosphere after being routed to a control device or a product recovery device.

(147) "Professional judgment" means the ability to render sound decisions based on professional qualifications and relevant greenhouse gas accounting experience.

(148) "Propane" (C_3H_8) means a normally straight chain hydrocarbon that boils at -43.67 degrees Fahrenheit.

(149) "Purchasing/selling entity" means an entity that is eligible to purchase or sell energy or capacity and reserve transmission services.

(150) "Pure" means consisting of at least 97 percent by mass of a specified substance. For facilities burning biomass fuels, this relates to the fraction of biomass carbon in the total amount of carbon in the fuel burned at the facility.

(151) "Purge gas" means nitrogen, carbon dioxide, liquefied petroleum gas, or natural gas used to maintain a non-explosive mixture of gases in a flare header or provide sufficient exit velocity to prevent regressive flame travel back into the flare header:

(152) "Qualifying facility" means a cogeneration or small power production facility that meets ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act.

(153) "Reasonable assurance" means a high degree of confidence that submitted data and statements should be treated as valid.

(154) "Recycled" refers to a material that is used or reused, or reclaimed.

(155) "Refinery fuel gas (still gas)" means gas generated at a petroleum refinery or any gas generated by a refinery process unit, which is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

(156) "Renewable energy" means resources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes, but is not limited to energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

(157) "Report year" means the calendar year for which emissions are being reported in the emissions data report.

(158) "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.

(159) "Retail provider" means an operator that is any electric corporation as defined in Public Utilities Code Section 218, electric service provider as defined in Public Utilities Code Section 218.3, public owned electric utility as defined in Public Resources Code Section 9604, community choice aggregator as defined in Public Utilities Code Section 331.1, the Western Area Power Administration, or the California Department of Water Resources.

(160) "Screening value" (SV) means the instrument reading (ppmv) obtained when components, including but not limited to valves, pump seals, connectors, flanges, open-ended lines and other equipment components, are evaluated for leakage as described in U.S. E.P.A. Method 21 – Determination of Volatile Organic Compound Leaks.

(161) "Sector" means a broad industrial categorization such as specified in section 95101(b).

(162) "Self-generation facility" means a facility dedicated to serving a particular retail customer, usually located on the customer's premises. The facility may either be owned directly by the retail customer or owned by a third party with a contractual arrangement to provide electricity to meet some or all of the customer's load.

(163) "Source" means a stationary point source or a collection of stationary point sources of the same type on the same facility.

(164) "Source stream" means a specific fuel type, raw material or product giving rise to emissions of relevant greenhouse gases at one or more emission sources as a result of its consumption or production.

(165) "Southwest" means Arizona, Nevada, Utah, Colorado, and western New Mexico.

(166) "Specified source of power" or "specified source" means a particular generating unit or facility whose electrical generation can be confidently tracked due to full or partial ownership or due to its identification in a power contract.

(167) "Specified wholesale sales" means wholesale electric power sales made by retail providers that can be matched to a specified source of power.

(168) "Standard conditions" means a temperature of 20 degrees Celsius (68 degrees Fahrenheit) and an absolute pressure of 760 mm (30 inches) of mercury.

(169) "Stationary" means neither portable nor self propelled and is operated at a single facility.

(170) "Stationary combustion source" means a stationary source of emissions from the production of electricity, heat, or steam, resulting from combustion of fuels in boilers, furnaces, turbines, kilns, and other facility equipment.

(171) "Still gas (refinery gas)" means any form or mixture of gases produced in refineries by distillation, cracking, reforming, and other processes.

(172) "Storage tank" means any container, reservoir, or tank used for the storage of organic liquids, excluding tanks which are permanently affixed to mobile vehicles such as railroad tank cars, tanker trucks or ocean vessels:

(173) "Substitute energy" means electric power delivered under a facility-specific contract that was not produced by the facility specified in the contract.

(174) "Sulfur hexafluoride (SF_6)" means a GHG consisting of a single sulfur atom and six fluorine atoms.

(175) "Sulfur recovery unit" means a refinery unit that removes sulfur from distillate fuel.

(176) "Supplemental firing" means an energy input to the cogeneration facility used only in the thermal process of a topping-cycle plant, or in the electric generating or manufacturing process of a bottoming-cycle cogeneration facility.

(177) "Tactical support equipment" is as defined in Title 17, California Code of Regulations, section 93116.2(ii).

(178) "Ton" means a short ton equal to 2000 pounds.

(179) "Topping cycle plant" means a cogeneration facility in which the energy input to the facility is first used to produce useful power output, and at least some of the reject heat from the power production process is then used to provide useful thermal energy.

(180) "Total organic carbon or TOC" means a measure of the total organic carbon molecules present in a sample.

(181) "Transferred CO_2" means carbon dioxide that is not emitted directly at the facility but is sold and transferred out of the installation as a pure substance.

(182) "Uncertainty" means a parameter, associated with the results of the determination of a quantity, that characterizes the dispersion of the values that could reasonably be attributed to the particular quantity, including the effects of systematic as well as random factors and expressed in percent and describes a confidence interval around the mean value comprising 95% of inferred values taking into account any asymmetry of the distribution of values.

(183) "Unspecified source of power" or "unspecified source" refers to electricity generation that cannot be matched to a particular generating facility. Unspecified sources of power may include power purchased from entities that own fleets of generating facilities such as independent power producers, retail providers, and federal power agencies and power purchased from electricity marketers, brokers, and markets.

(184) "Useful thermal output" means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

(185) "Verification" means the process used to ensure that an operator's emissions data report is free of material misstatement and complies with ARB's procedures and methods for calculating and reporting GHG emissions.

(186) "Verification body" means an ARB accredited firm or AQMD/APCD that is able to render a verification opinion and provide verification services for operators subject to reporting under this article.

(187) "Verification cycle" means one year of full verification and the proceeding two years of verification requirements for operators subject to annual verification. For operators subject to triennial verification, a "verification cycle" means one year of full verification, and if elected, the proceeding two years of less intensive verification. A verification cycle can not exceed 3 calendar years.

(188) "Verification opinion" means the final opinion rendered by a verification firm attesting whether or not an operator's emissions data report is free of material misstatement and that all verification process checklist items have been completed by the verification firm.

(189) "Verification services" means services provided during verification as specified in section 95131, including but not limited to reviewing an operator's emissions data report, verifying its accuracy according to the standards specified in this article, assessing the operator's compliance with this article, and submitting a verification opinion to the ARB.

(190) "Verification team" means more than one verifier, including all subcontractors, acting for a verification body to provide verification services for a client. The lead verifier for the verification team shall be a lead verifier in the verification body.

(191) "Verified emissions data report" means an emissions data report that has been reviewed and approved by a third-party verifier and accepted by the ARB.

(192) "Verifier" means an individual accredited by ARB to carry out verification services as specified in section 95131.

(193) "Wastewater" means any process water which contains oil, emulsified oil, or other organic compounds which are not recycled or otherwise used in a facility.

(194) "Wastewater separator" means equipment used to separate oils and water from locations downstream of process drains.

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95103. General Greenhouse Gas Reporting Requirements.

(a) ***General Reporting Requirement.*** The operators listed in section 95101(b) shall submit greenhouse gas emissions data reports on the schedule specified in section 95103(b).

(1) The operator shall submit a report for the 2008 report year that applies best available data and methods to develop emissions estimates. The operator shall submit a report for the 2009 and subsequent report years that meets all specifications of this article.

(2) ***Stationary sources.*** The operator shall identify, calculate, and report all direct CO_2, N_2O, and CH_4 emissions from stationary combustion, process, and fugitive sources at the facility as specified in sections 95110 through 95115. The operator shall calculate and report each GHG separately for each fuel type used, and for each process unit as applicable, as specified in sections 95110 through 95115 except where specific unit-level fuel use is not separately metered.

(3) The operator shall separately identify, calculate and report all direct emissions of CO_2 resulting from combustion of biomass-derived fuels as specified in sections 95110 through 95115;

(4) ***Mobile sources.*** The operator may elect to identify, calculate, and separately report facility CO_2, N_2O, and CH_4 emissions from mobile combustion using the methods specified in section 95125(i).

(5) The operator shall separately calculate and report consumption of purchased or acquired electricity, heat, cooling or steam when specified in sections 95110 through 95115.

(6) ***Emissions calculation and reporting procedures for de minimis sources.*** The operator may elect to designate up to 3 percent of the facility's CO_2 equivalent emissions fro discrete sources, not to exceed a total of 10,000 metric tonnes, as *de minimis* for purposes of applying the calculation methods specified in this article. The operator may estimate these emissions using alternative methods of the operator's choosing, subject to the concurrence of the verification team that the use of such methods provides reasonable assurance that the emissions so designated and estimated do not exceed the applicable *de minimis* limit. The operator shall separately identify and include in the emissions data report the emissions designated as *de minimis*. The operator shall determine CO_2 equivalence according to the 100-year global warming potentials provided in Appendix A.

(7) The operator shall report information in the units of measurement specified in sections 95110 through 95115, to the nearest whole unit.

(8) ***Fuel analytical data capture.*** When the applicable emissions estimation methodologies in sections 95110 through 95125 require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

(A) If the operator is unable to obtain a fuel analytical data capture rate such that more than 20 percent of emissions for a source cannot be directly accounted for, and the source(s) for which data are missing are not subject to separate fuel analytical data capture requirements specified in 40 CFR Part 75 or Part 60, the emissions from that source shall be considered unverifiable for the report year.

(B) If the fuel analytical data capture rate is at least 80 percent for any emissions source as applicable in sections 95110 through 95125, and that source is not subject to separate fuel analytical data capture requirements specified in 40 CFR Part 75 or Part 60, the operator shall use the mean of the fuel analytical data results captured to substitute for the missing values for the period of missing data.

(9) The operator shall employ procedures for the measurement of fuel activity data (mass or volume flow) that quantifies fuel use with an uncertainty of no more than ± 2.5 percent. All fuel activity measurement devices shall be maintained and calibrated in a manner and at a frequency required to maintain this level of measurement uncertainty.

(10) In cases where this article specifies a choice between use of a fuel-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate CO_2 emissions from combustion, the operator shall make this choice and continue to use the method chosen for all future emissions data reports, except as specified in section 95103(a)(10)(A).

(A) When an operator elects to install a new CEMS or CEMS CO2 monitor prior to January 1, 2010, the operator may report combustion emissions on the basis of the fuel-based calculation specified in this article for the 2008 and 2009 report years. The new CEMS or CEMS CO2 monitor shall be installed and operated according to requirements in section 95125(g), and become operational for purposes of emissions reporting by January 1, 2010.

(b) ***Reporting Schedule – Existing Facilities.*** Operators of the facilities and entities listed in section 95101(b) that are operational as of January 1, 2008 must submit greenhouse gas emissions data reports to ARB for emissions in 2008 and

each future calendar year. Operators shall submit these reports in the calendar year following each report year as specified in the following schedule:

(1) Operators of general stationary combustion facilities outside the oil and gas sector (NAICS 211111) and electric generating facilities and cogeneration facilities not under the operational control of a retail provider, cement plant operator, refinery operator, or hydrogen plant operator subject to the requirements of this article shall submit a complete GHG emissions data report to the ARB no later than April 1 of each calendar year beginning in 2009, for emissions occurring in the previous calendar year.

(2) Retail providers, marketers, operators of general stationary combustion facilities within the oil and gas sector (NAICS 211111), operators of cement plants, petroleum refineries, and hydrogen plants subject to the requirements of this article shall submit a complete GHG emissions data report to the ARB no later than June 1 of each calendar year beginning in 2009, for emissions occurring in the previous calendar year. When the operator has operational control of an electric generating facility or cogeneration facility subject to the requirements of this article, the operator shall submit by the same date an emissions data report for this facility that meets the requirements of sections 95111 and 95112 as applicable.

(c) ***Verification – Existing Facilities.*** Operators of all facilities subject to the reporting requirements of this article shall obtain verification services for emissions data reports submitted in 2010 and subsequent years from a verification body that meets the requirements of sections 95131 through 95133. Verification shall be obtained as provided in the following schedule.

(1) ***Annual schedule.*** Retail providers, marketers, and operators of petroleum refineries, hydrogen plants, general stationary combustion facilities in the oil and gas sector (NAICS 211111), and electric generating and cogeneration facilities that combust fossil fuels and have a total nameplate generating capacity $\geq$10 MW shall obtain verification of each annual emissions data report.

(2) ***Triennial schedule.*** Operators of cement plants and electric generating and cogeneration facilities that combust pure biomass fuels or have a total nameplate generating capacity <10 MW shall obtain verification of the emissions data report submitted in 2010, and of the emissions data reports submitted every third year thereafter. Operators of general stationary combustion facilities outside the oil and gas sector (NAICS 211111) shall obtain verification of the emissions data report submitted in 2011, and of the emissions data reports submitted every third year thereafter. If any change in materials or operations occurs at a cement plant that requires a change in

a permit filed with an air pollution control district or air quality management district, the operator of the cement plan shall obtain verification of the submitted emissions data report for the first full calendar year following the permit change.

(3) ***Verification opinion due dates.*** In the calendar years when verification is required, the operator shall submit to the ARB the verification opinion specified in section 95131(c)(1) no later than six months after the deadlines specified in section 95103(b) for submitting emission reports.
   (A) For operators with an emissions data report due April 1, as specified in section 95103(b)(1), the verification opinion must be submitted no later than October 1 of the same calendar year;
   (B) For operators with an emissions data report due June 1, as specified in section 95103(b)(2), the verification opinion must be submitted no later than December 1 of the same calendar year.

(d) ***Reporting Schedule – New Facilities.*** All operators described in section 95101(b) that commence operation after January 1, 2008 must report greenhouse gas emissions. The initial facility GHG emissions data report data shall be submitted based on emissions produced during the first full calendar year of operation. The emissions data report and a verification opinion shall be submitted during the year following the first full calendar year of operation, by the month and day of the year as specified for the relevant industrial sector in sections 95103(b) and (c).

(e) ***Cessation of Reporting After Reduced Emissions.***

(1) When the operation of a general stationary combustion facility subject to the requirements of this article is changed such that the operator has reported less than 20,000 metric tons of CO_2 from combustion for three consecutive report years, the operator shall be exempted from further reporting until CO_2 from combustion again exceed 25,000 metric tonnes in any future calendar year.

(2) When the operation of a power generation or cogeneration facility subject to this article is changed such that the operator has reported less than 2000 metric tons of CO_2 for three consecutive report years, the operator shall be exempted from further reporting until CO_2 again exceeds 2,500 metric tonnes in any future calendar year.

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95104. Greenhouse Gas Emissions Data Report.

(a) ***Emissions Data Report.*** Operators subject to this article shall submit emissions data reports according to the schedule specified in section 95103(b). Emissions data reports shall include the information below and the additional data specified in sections 95110 through 95115, as applicable.

(1) Facility name, identification number, physical address, mailing address, location, NAICS code;
(2) A description of facility or entity boundaries for the report, including geographic location;
(3) Name of the person responsible for reporting and his or her contact information, including e-mail address and telephone number;
(4) The report year;
(5) The direct GHG emissions, electricity transactions information and other data specified in sections 95110 through 95115 as applicable to the operator, including emissions occurring during routine maintenance, start-ups, shutdowns, upsets and downtime subject to the limitations of section 95103(a)(8);
(6) Indirect electric and thermal energy consumed for electricity, heat, steam, and cooling when required for the facility as specified in sections 95110 through 95115;
(7) Efficiency metrics when required for the facility as specified in sections 95110 through 95115;
(8) The parent company or companies with ownership of the facility that is the subject of the report, and a list of all facilities and offices in California owned or operated by that parent company, including subsidiary facilities and offices not subject to the requirements of this article. The operator may elect to have this information submitted separately by the parent company for all facilities under its ownership and operational control, with indication of the parent company's ownership share and operational control for each facility;
(9) Contact information for the companies and facilities provided in section 95104(a)(8), including physical addresses, e-mail addresses if available, and telephone numbers;
(10) A signed and dated statement provided by the operator that the GHG report has been prepared in accordance with this article, and that the statements and information contained in the emissions data report are true and accurate to the best knowledge and belief of the certifying official.

(b) ***Maintaining the GHG Inventory Program.*** To facilitate annual compilation of the emissions data report, the operator shall maintain a greenhouse gas inventory program that ensures that emissions calculations and electricity transactions information are transparent, accurate, and independently verifiable. The operator shall establish, document, implement, and maintain data acquisition and handling activities for the calculation and reporting of greenhouse gas

emissions. Such activities shall include measuring, monitoring, analyzing, recording, processing and calculating the parameters specified by this article.

(c) ***Data Completeness.*** To facilitate replication of the emissions and electricity transactions information reported as specified by this article by the verification team or another party including ARB, the operator shall establish, document, implement and maintain a system that provides clarity, transparency, and completeness of data. The operator shall make every reasonable effort to complete emissions data reports that contain no material misstatements and are in conformance with the emission calculation methodologies and factors specified by this article. The operator shall implement systems of internal audit, quality assurance, and quality control for the reporting program and the data reported.

(d) ***Revisions.*** The operator may revise a submitted emissions data report in the following circumstances. The operator shall maintain documentation to support any revisions made to a previously submitted emissions data report. Documentation for all emissions data report submittals shall be retained by the operator for five years, as specified in section 95105.

(1) If during the course of receiving verification services and prior to completion of a verification opinion an operator chooses to make a correction or improvement to the report.

(2) If an operator wishes to correct or improve an emissions data report not subject to verification, provided those changes are documented and approved by ARB;

(3) If an operator wishes to correct or improve a verified emissions data report within five years of submittal, in which case the revision must also be made subject to verification.

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95105. Document Retention and Record Keeping Requirements.

(a) The operator shall establish and maintain procedures for document retention and record keeping. The operator shall retain documents regarding the design, development and maintenance of the GHG inventory, in paper, electronic or other format, for a period of not less than five years following each emissions data report. The documented and archived GHG emissions estimation data shall be sufficient to allow for the verification of each emissions data report.

(b) Upon request by ARB, the operator shall provide to ARB within 20 days any data used to develop an emissions data report.

(c) In addition to information submitted as part of the emissions data report, each operator shall retain, at a minimum, the following information for at least five years after the submission of the report:

(1) The list of all source streams included in the emission estimates;
(2) The activity data used to calculate emissions for each source stream, categorized by process and fuel or material type;
(3) Documentation of the process for collecting activity data for the facility and its source streams;
(4) Any GHG emissions calculations and methods used;
(5) All emission factors used for emission estimates, including documentation for any factors not provided by ARB;
(6) Any facility or other input data used for emission estimates;
(7) Documentation of biomass fractions for specific fuels;
(8) Record of electric power purchase and sale transactions, including imports and exports of power from California;
(9) The activity data, emissions, or other data submitted to the ARB under this article;
(10) Names and documentation of key facility personnel involved in emissions calculating and reporting;
(11) The emissions data report; and
(12) Any other information that is required for the verification of the emissions data report.

(d) For measurement based methodologies, each operator shall retain the following information for at least five years after the submission of the emissions data report:

(1) The list of all emission sources monitored;
(2) Collected monitoring data;
(3) The data used for the uncertainty analysis of emissions from each emissions source, categorized by process;
(4) Quality assurance and quality control information including information regarding measurement gaps as applicable;
(5) The data used for the corroborating calculations;
(6) A detailed technical description of the continuous measurement system including the documentation of the approval from the competent authority;
(7) Raw and aggregated data from the continuous measurement system; including documentation of changes over time and the log book on tests, down-times, calibrations, servicing and maintenance;
(8) Documentation of any changes in continuous measurement systems.

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95106. Confidentiality.

(a) The following information is public information and shall not be designated as confidential: estimates of direct facility emissions of any greenhouse gases by major source category (combustion, process, fugitive).

(b) Except as provided in section 95106(a), any person submitting information to the ARB pursuant to this article may designate such information as confidential because it is a trade secret or otherwise exempt from public disclosure under the California Public Records Act (Government Code section 6250 et seq.). All requests for confidentiality shall be handled in accordance with the procedures specified in title 17, California Code of Regulations, sections 91000 to 91022.

NOTE: Authority cited: Sections 38580, 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 38580, 39600, 41511, and 38530, Health and Safety Code.

95107. Enforcement.

(a) Failure to submit any report or information required by this article shall constitute a single, separate violation of this article for each day until the information is submitted.

(b) Knowing submission of false information, with intent to deceive, to the Executive officer or a verifier, shall constitute a single, separate violation of the requirements of this article for each day after the information has been received by the Executive Officer.

(c) Late submittal of an emissions data report or verification opinion shall constitute a single, separate violation of the requirements of this article for each day that the information has not been submitted beyond the specified reporting dates.

NOTE: Authority cited: Sections 38580, 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 38580, 39600, 41511, and 38530, Health and Safety Code.

95108. Severability.

Each part of this article shall be deemed severable, and in the event that any provision of this article is held to be invalid, the remainder of this article shall continue in full force and effect.

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95109. Incorporation by Reference.

The following documents are incorporated by reference in this article. These materials are incorporated as they exist on the date of the approval.

(a) American Society for Testing and Materials (ASTM) D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (2006), ASTM D240-02 (2007), ASTM D4809-00 (Reapproved 2005), ASTM 5373-02 (Reapproved 2007), ASTM D5291-02 (2007), ASTM D3238-95 (Reapproved 2005), ASTM D2502-04 (Reapproved 2002), ASTM D2503-92 (Reapproved 2002), ASTM D1945-03 (Reapproved 2006), ASTM D1946-90 (Reapproved 2006), ASTM D6866-06a (2006), ASTM D388–92 (1992), ASTM Specification D1835-05 (2005), ASTM Specification D3699 (2006), ASTM Specification D4814-07a (2007).

(b) *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities*, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board (ARB), February 1999.

(c) *Control of Emissions from Refinery Flares*, South Coast Air Quality Management District, Amended November 4, 2005.

(d) *U.S. EPA TANKS Version 4.09D*, US Environmental Protection Agency, October 2005.

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 2. Requirements for the Mandatory Reporting of Greenhouse Gas Emissions from Specific Types of Facilities

95110. Data Requirements and Calculation Methods for Cement Plants.

(a) ***Greenhouse Gas Emissions Data Report.*** The operator of a cement plant shall include the following information in the greenhouse gas emissions data report for each report year.

(1) Total Emissions:
- (A) Total CO_2 emissions (metric tonnes)
- (B) Total CH_4 emissions (metric tonnes)
- (C) Total N_20 emissions (metric tonnes)

(2) Process CO2 Emissions from Cement Manufacturing:
- (A) Clinker Based Methodology for CO_2 Estimates
  1. Clinker emission factor (kg CO_2/metric tonnes clinker)
     a. Quantity of clinker produced (metric tonnes)
     b. CaO Content of clinker (percent)
     c. MgO Content of clinker (percent)
     d. Non-carbonate CaO (percent)
     e. Non-carbonate MgO (percent)
  2. Cement kiln dust (CKD) emission factor (kg CO_2/metric tonnes clinker)
     a. Plant specific CKD calcination rate (unitless)
     b. Quantity of CKD discarded (metric tonnes)
  3. CO_2 emissions from clinker production (metric tonnes)

- (B) Total Organic Carbon (TOC) Content in Raw Materials:
  1. Amount of raw material consumed in the report year (metric tonnes)
  2. Organic carbon content of raw material (percent)
  3. CO_2 emissions from TOC in Raw Materials (metric tonnes)

(3) Stationary Combustion:
- (A) Fuel consumption by fuel type (scf, gallons, or tons)
- (B) Average carbon content by fuel type if measured or provided by fuel supplier (kg Carbon/MMBtu)
- (C) Average high heat value by fuel type if measured or provided by fuel supplier (HHV)
- (D) CO_2 emissions by fuel type (metric tonnes)
  1. CO_2 emissions from biomass-derived fuels (metric tonnes)
- (E) CH_4 emissions by fuel type (metric tonnes)
- (F) N_2O emissions by fuel type (metric tonnes)

(4) Fugitive Emissions:
  (A) Coal consumption by coal type (metric tonnes)
  (B) Emission factor (scf CH_4/metric tonne)
  (C) CH_4 Emissions from coal storage (metric tonnes)

(5) Indirect Energy Usage
  (A) Electricity purchases from each electricity provider (kWh)
  (B) Steam, heat, and cooling purchases from each energy provider (Btu)

(6) Efficiency Metrics
  (A) CO_2 emissions per metric tonne of cementitious product
  (B) CO_2 emissions per metric tonne of clinker

(b) ***Calculation of CO_2, N_2O, and CH_4 Emissions.*** Operators of cement plants shall calculate emissions and indirect energy usage for each source as specified in this section.

(1) ***Total CO_2 Emissions.*** Operators of cement plants shall calculate total CO_2 emissions from either (A) or (B) below.

  (A) Continuous emissions monitoring systems (CEMS) as specified in section 95125(g). Operators of cement plants that measure CO_2 emissions using CEMS shall also report fuel usage by fuel type., or

  (B) Process CO_2 emissions from cement manufacturing as specified in section 95110(c) and stationary combustion CO_2 emissions as specified in section 95110(d).

(2) ***Direct N_2O and CH_4 Emissions.*** Operators of cement plants shall calculate N_2O and CH_4 emissions from fuel combustion as specified in section 95125(b).

(3) ***Direct Fugitive Emissions*** . Operators of cement plants shall calculate fugitive CH_4 emissions from coal fuel storage as specified in section 95125(j).

(4) ***Indirect Energy Usage.*** Operators of cement plants shall calculate indirect electricity and thermal energy purchased or acquired and consumed as specified in sections 95125(k)-(l).

(5) ***Cogeneration.*** Operators of cement plants with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(6) ***Efficiency Metrics.*** Operators of cement plants shall calculate CO_2 emissions per metric tonne of cementitious product as specified in section 95110(e).

(c) ***Process CO_2 Emissions from Cement Manufacturing.*** Operators of cement plants shall calculate CO_2 emissions from clinker production using the Clinker-Based Methodology as specified in section 95110(c)(1). Operators shall calculate CO_2 process emissions from the total organic carbon (TOC) content in raw materials as specified in section 95110(c)(2).

(1) **Clinker-Based Methodology.** Operators of cement plants shall calculate CO2 emissions from clinker production using a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section, 95110(b)(1).

Clinker-Based Methodology

CO_2 Emissions (metric tonnes) = [(Cli) x (EF_{Cli}) + (CKD) x (EF_{CKD})]

Where:

Cli	=	Quantity of clinker produced, metric tonnes
EF_{Cli}	=	Clinker emission factor, metric tonnes CO_2/metric tonnes clinker computed as specified in section 95110(b)(1)(A)
CKD	=	Quantity CKD discarded
EF_{CKD}	=	CKD emission factor, computed as specified in section 95110(b)(1)(B)

(A) ***Clinker Emission Factor (EF_{Cli}).*** Cement plant operators shall calculate a plant-specific clinker emission factor for each report year based on the percent of measured CaO and MgO content in the clinker and adjusted to account for non-carbonate CaO and MgO using the Clinker Emission Factor equation specified in this section, 95110(b)(1)(A). Each fraction of non-carbonate sources (e.g., steel slag, calcium silicates or fly ash) of CaO and MgO shall be subtracted from the total amount of CaO and MgO content of the clinker.

Clinker Emission Factor:

EF_{Cli} = [(CaO content – non-carbonate CaO) x Molecular ratio of CO_2/CaO] + [(MgO Content – non-carbonate MgO) x Molecular Ratio of CO_2/MgO]

Where:

CaO Content (by weight)	=	CaO content of Clinker (%)
Molecular Ratio of CO_2/CaO	=	44g/56g = 0.785
MgO Content(by weight)	=	MgO content of Clinker (%)
Molecular Ratio of CO_2/MgO	=	44g/40g = 1.092
Non-carbonate CaO (by weight)	=	Non-carbonate CaO of Clinker (%)
Non-carbonate MgO(by weight)	=	Non-carbonate MgO of Clinker (%)

(B) ***CKD Emission Factor.*** Operators of cement plants that generate CKD and do not recycle the CKD back to the kiln shall calculate a plant-specific CKD emission factor. The CKD emission factor shall be calculated using the CKD Emission Factor equation specified in this section, 95110(b)(1)(B). The CKD emission factor shall be calculated using the Plant-specific CKD Calcination Rate equation below.

CKD Emission Factor

$$EF_{CKD} = \frac{\frac{EF_{Cli}}{1+EF_{Cli}} \times d}{1 - \frac{EF_{Cli}}{1+EF_{Cli}} \times d}$$

Where:

EF_{CKD} = CKD Emission Factor
EF_{Cli} = Clinker Emission Factor
d = CKD Calcination Rate

Plant-specific CKD Calcination Rate

$$d = 1 - \frac{fCO_{2CKD} \times (1 - fCO_{2RM})}{(1 - fCO_{2CKD}) \times fCO_{2RM}}$$

Where:

fCO_{2CKD} = weight fraction of carbonate CO_2 in the CKD
fCO_{2RM} = weight fraction of carbonate CO_2 in the raw material

(2) ***TOC Content in Raw Materials.*** Operators of cement plants shall calculate CO_2 emissions from the TOC content in raw materials by applying an assumed 0.2 percent assumed organic carbon factor to the amount of raw material consumed then converting from carbon to CO_2 using the equation below.

TOC Content in Raw Materials

CO_2 emissions = ($TOC_{R.M.}$) x (R.M.) x (3.664)

Where:

$TOC_{R.M}$ = *0.2% = Organic carbon content of raw material (%)*
R.M. = *The amount of raw material consumed (metric tonnes/yr)*
3.664 = *The CO_2 to carbon molar ratio*

(d) ***Stationary Combustion CO_2 Emissions.*** Operators of cement plants shall calculate stationary combustion CO_2 emissions at cement kiln and non-kiln units

separately based on the quantity and type of fuel combusted during each report year as specified in this section.

(1) Natural Gas: Operators of cement plants that combust natural gas shall calculate CO_2 emissions resulting from the combustion of natural gas using the method provided in section 95125(c) or section 95125(d).

(2) Coal or Petroleum Coke: Operators of cement plants that combust coal or petroleum coke shall calculate CO_2 emissions using the method provided in section 95125(d). Operators of cement plants shall measure and record coal consumption and carbon content weekly.

(3) Other Fossil Fuels: Operators of cement plants that combust No. 1, No. 2 fuels, gasoline, diesel fuel, middle distillates (such as diesel, fuel oil, or kerosene), residual oil, or LPG (such as ethane, propane, isobutene, n-Butane, or unspecified LPG) shall calculate CO_2 emissions using the method provided in section 95125(c) or section 95125(d).

(4) Refinery Fuel Gas: Operators of cement plants that combust refinery gas, still gas, process gas, or associated gas shall calculate CO_2 emissions using the method provided in section 95125(e).

(5) Landfill Gas or Biogas: Operators of cement plants that combust landfill gas or biogas from waste water treatment shall calculate CO_2 emissions using the method provided in section 95125(c) or section 95125(d).

(6) Biomass or Municipal Solid Waste: Operators of cement plants that combust biomass or municipal solid waste shall calculate CO_2 emissions using the method provided in section 95125(a) or section 95125 (h)(3).

(7) Alternative Fuels: Operators of cement plants that combust impregnated saw dust, solvents, plastics, waste oil, fossil-based wastes, tire-derived fuel, diaper waste, charcoal, and any other alternative fuel shall calculate CO_2 emissions using the method provided in section 95125(c) or section 95125(d).

(8) Co-Firing of Fuels
   (A) Operators of cement plants that co-fire more than one fossil or alternative fuel shall calculate CO_2 emissions separately for each fuel type using methods specified in this section 95110(d).
   (B) Operators of cement plants that co-fire biomass-derived fuels with fossil fuels shall calculate CO_2 emissions associated with each fuel using the method provided in section 95125(a) or (h)(3).

(9) Start-Up Fuels: Operators of cement plants that primarily combust biomass-derived fuels but that combust fossil fuels for start-up, shut-down, or

malfunction operating periods only, shall report CO_2 emissions from the fossil fuels using methodologies in section 95125(a) or methods specified in this section by fuel type.

(e) ***Efficiency Metrics.*** Cement plant operators shall calculate for the report year the CO_2 emissions generated per metric tonne of cementitious product and CO_2 emissions generated per metric tonne of clinker using the efficiency metric equations specified in this section, 95110(e).

(1) CO_2 Emissions per metric tonne of Cementitious Product

$$\text{CO}_2\text{ emissions} = \frac{\text{Direct CO}_2\text{ emissions from cement manufacturing}}{\left(\begin{array}{l}\text{Own clinker}\\ \text{consumed or}\\ \text{added to stock}\end{array}\right)+\left(\begin{array}{l}\text{Own clinker}\\ \text{sold directly}\end{array}\right)+\left(\begin{array}{l}\text{gypsum, limestone,}\\ \text{CKD \& clinker}\\ \text{substitutes consumed}\\ \text{for blending}\end{array}\right)+\left(\begin{array}{l}\text{cement}\\ \text{substitutes}\end{array}\right)}$$

(2) CO_2 Emissions per metric tonne of Clinker

$$\text{CO}_2\text{ emissions} = \frac{\text{Direct CO}_2\text{ emissions from cement manufacturing}}{(\text{Own clinker consumed or added to stock})+(\text{own clinker sold directly})}$$

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95111. Data Requirements and Calculation Methods for Electric Generating Facilities, Retail Providers and Marketers.

(a) ***Electric Generating Facilities.*** The operator of an electric generating facility shall include the following information in the greenhouse gas emissions data report for each report year and shall meet the requirements in sections 95111 (c) through 95111(i) in preparing the greenhouse gas emissions calculations for inclusion in the report.

(1) At the facility level, operators shall include:

(A) ARB designated facility identification number (ID), nameplate generating capacity in megawatts (MW), and net power generated in the report year in megawatt hours (MWh);

(B) Fuel consumption by fuel type (scf, gallons, tons, or bone dry tons);

(C) Average high heat value (MMBtu per unit of mass or volume) by fuel type based on values measured by the operator or the fuel supplier as specified in section 95125(c)(1)(B) if the operator elects to calculate CO_2 emissions using methods specified in section 95125(c) or (e) pursuant to the operator's options as specified in section 95111(c). If high heat value is not measured by the operator or the fuel supplier using methods specified in section 95125 (c)(1)(B), then the operator shall report steam produced in pounds. Boiler efficiency may also be reported;

(D) Average carbon content by fuel type as a percent based on values measured by the operator or the fuel supplier as specified in section 95125(d) if the operator elects to calculate CO_2 emissions using methods defined in section 95125(d) or (e) pursuant to the operator's options as specified in section 95111(c);

(E) CO_2, N_2O, and CH_4 emissions from fuel combustion in metric tonnes;

(F) Process CO_2 emissions from acid gas scrubbers or acid gas reagent used in the combustion source, if applicable, in metric tonnes;

(G) Fugitive CH_4 emissions from coal storage from coal-fired facilities, if applicable, in metric tonnes;

(H) Fugitive emissions of HFC related to the operation of cooling units that support power generation, if applicable, in kilograms;

(I) Fugitive CO_2 emissions from geothermal facilities, if applicable, in metric tonnes;

(J) Fugitive SF_6 from equipment located at the facility and that the operator is responsible for proper working order, if applicable, in kilograms;

(K) Wholesale sales (MWh) exported directly out-of-state, if known, that are additional to electricity transactions reported as specified in section 95111(b)(2)(D). Sales shall be aggregated by counterparty and measured at the busbar. The operator shall report the region of destination as Pacific Northwest (PNW) or Southwest (SW).

(2) For each generating unit operators shall include:

(A) Generating unit ID designated by ARB, nameplate generating capacity (MW), and net power generated (MWh);

(B) Fuel consumption by fuel type (scf, gallons, tons or bone dry tons);

(C) CO_2, N_2O, and CH_4 emissions from fuel combustion in metric tonnes;

(D) Wholesale sales (MWh) exported directly out-of-state by generating unit if applicable and as specified in section 95111(a)(1)(K).

(3) ***Aggregation of Multiple Units.*** If a facility lacks the necessary metering or monitoring equipment to measure data individually for each generating unit, the operator may report data on an aggregated basis for multiple units that combust the same fuel type.

(4) ***Cogeneration Facilities.*** Operators of generating facilities with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(5) ***Out-of-State Operators.*** Operators of out-of-state generating facilities may voluntarily submit a greenhouse gas emissions data report that meets applicable requirements defined in this article for generating facilities.

(6) ***Asset Owning/Asset Controlling Suppliers.*** Asset owning or asset controlling suppliers that do not purchase power or use substitute power accounting for more than 10% of the power they sell, may voluntarily request that ARB assign a supplier-specific ID to the supplier's fleet of generating facilities. Asset owning or asset controlling suppliers that choose this option shall:

(A) Meet the requirements in this article as applicable for each generating facility in the supplier's fleet;

(B) Include in their greenhouse gas emissions data report the list of the generating facilities in their fleet along with the ARB designated facility ID;

(C) Retain for verification purposes documentation that the power sold by the supplier originated from the supplier's fleet of facilities and either that the fleet is under the supplier's operation control or that the supplier serves as the fleet's exclusive marketer;

(D) Provide the supplier-specific ID to retail providers who purchase unspecified power from the supplier's fleet.

(b) ***Retail Providers and Marketers.***

(1) ***General Requirements for Retail Providers and Marketers.*** Retail providers and marketers shall meet the following general requirements in preparing their greenhouse gas emissions data report for each report year. Retail providers and marketers shall include electricity transactions associated with both renewable and nonrenewable energy sources of power.

(A) When reporting electricity transactions:

1. Specify the amount of electricity in MWh;
2. From specified sources, specify the amount of electricity as measured at the busbar;
3. From unspecified sources, specify the amount of electricity as measured at the first point of receipt for which the reporting entity has information;
4. From specified sources, specify the facility name, the ARB designated facility ID, and the generating unit ID for the unit generating the power, if applicable;
5. Specify region of origin and region of destination;
6. Retail providers shall aggregate and specify electricity transactions by counterparty;
7. Marketers shall aggregate and specify electricity transactions by power supplier;
8. Specify the amount of electricity (MWh) that is null power when applicable;
9. Specify electricity received under exchange agreements as purchases and electricity delivered under exchange agreements as wholesale sales;
10. Specify purchases of substitute energy and provide the same information required for other types of power purchases in this article as applicable.

(B) If the region of origin or region of destination for an electricity transaction cannot be documented, the retail provider or marketer shall designate the region as unknown.

(C) ***Power Wheeled through California.*** When reporting power transactions imported into California or exported out of California, exclude the amount of power imported into California that terminates in a location outside of California, as measured at the first California point of delivery.

(D) ***California Department of Water Resources (DWR).*** The California Department of Water Resources shall include all applicable information identified in this article for retail providers including amount of power used by DWR, itself.

(E) ***Multi-jurisdictional Utilities.*** Multi-jurisdictional utilities shall include information required for retail providers in this article as applicable for the service territory that includes California end-use customers.

(F) ***Western Area Power Administration (WAPA).*** The Western Area Power Administration shall include information required of retail providers in this article as applicable to serving end use California customers and reporting fugitive SF_6. In particular, WAPA shall include electricity transactions related to sources of electricity located in California that are used to serve end-use California customers, power imported to California to serve end-use customers including transactions from facilities owned by the Bureau of Reclamation on the Lower Colorado River, and power exported from California.

(2) ***Greenhouse Gas Emissions Data Report: Retail Providers and Marketers.*** Retail providers and marketers shall include the following information in the greenhouse gas emissions data report for each report year.

(A) Fugitive emissions of SF_6 (kg) related to transmission and distribution systems, substations, and circuit breakers located inside California that the retail provider or marketer is responsible to maintain in proper working order. SF_6 emissions shall be calculated using the methodology specified in 95111(f).

(B) Power imported (MWh) from specified sources with final point of delivery in California and designate the region of origin as PNW or SW.

(C) Power imported (MWh) from unspecified sources with final point of delivery in California. The retail provider or marketer shall designate the region of origin as PNW, SW, or unknown and shall retain for

verification purposes NERC E-tags as confirmation of the region of origin.

(D) Power exported (MWh) from specified sources located inside California and designate the region of destination (PNW, SW, or unknown).

(E) Power exported (MWh) from unspecified sources located inside California and designate the region of destination (PNW, SW, or unknown).

(F) ***Electricity transactions wheeled through California***. Power imported (MWh) into California that terminates in a location outside of California, as measured at the first California point of delivery. The retail provider or marketer shall specify these transactions separately by the counterparty supplying power and specify the region of origin (PNW or SW). The retail provider or marketer shall retain for purposes of verification, NERC E-tags to confirm the transactions

(G) Retail providers shall include in their greenhouse gas emissions data report for each report year the additional information listed in section 95111(b)(3).

(3) ***Greenhouse Gas Emissions Data Report: Additional Requirements for Retail Providers Only.*** Retail providers shall include the following information in the greenhouse gas emissions data report for each report year, in addition to the information identified in sections 95111(b)(1-2).

(A) The information listed in section 95111(a) for each generating facility over which the retail provider has operational control.

(B) Retail providers shall include the facility name, ARB designated facility ID, nameplate generating capacity (MW) and net power generated in the report year (MWh) for generating facilities for which they have operational control that are solely powered by nuclear, hydroelectric, wind, or solar energy.

(C) Total retail sales megawatt hours (MWh). Multi-jurisdictional utilities shall include total retail sales for their service territories that include California customers, the portion of total annual retail sales to California customers only, and the ratio of retail sales to California customers only divided by the retail sales for the service area that includes California customers.

(D) Retail sales (MWh) from specified sources that use renewable energy may be reported as a subset of total retail sales in order to reflect special retail programs to reduce greenhouse gases. Retail providers

who choose to report retail sales for these programs shall aggregate sales by specified facility and include the facility name, the ARB designated ID, and a description of the program.

(E) Power purchased or taken (MWh) from in-state specified sources. For these purchases, the retail provider shall designate the region of origin as California.

(F) Power purchased or taken (MWh) from hydroelectric generating facilities with nameplate capacity of > 30 MW or from nuclear facilities (that are not California eligible renewable resources) shall be listed as one of the following:

1. Power purchased with a contract in effect prior to January 1, 2008 that remains in effect or has been renewed without interruption;
2. Power purchased not meeting the stipulation specified in section 95111(b)(3)(F)(1).

(G) Power purchased (MWh) from unspecified sources within California. For these purchases the retail provider shall designate the region of origin as one of the following:

1. From the CAISO pooled real-time market;
2. From the CAISO pooled integrated forward market;
3. From California but other than from the pooled CAISO markets;
4. From a region of origin that is unknown. Unspecified power purchased from an unknown region shall be reported as an import in section 95111(b)(2)(C).

(H) ***Native Load.*** The retail provider may elect to designate the power taken from a generating facility operated by the retail provider and power purchased or taken from other specified sources as serving native load if the facility meets one of the following criteria and shall state which of the criteria were met:

1. The generating facility is a California eligible renewable resource and, prior to the reporting date, the reporting entity has retired the WREGIS certificates associated with the power received from the facility during the report year.
2. The generating facility is a hydroelectric generation facility whose output the reporting entity takes whenever it is available.
3. The generating facility is a base-load facility running at an average annual capacity factor of 60 percent or greater. If a facility is designated as serving native load on this basis, all generating facilities from which the retail provider purchases or

takes specified power that run at the same or greater average annual capacity factor shall also be designated as serving native load.

4. The generating facility is a Qualifying Facility whose generation the reporting entity purchases under a power contract.

(I) Retail providers shall designate wholesale sales as inside California only if those sales go to other retail providers or to marketers who provide documentation that the sale went to the California region. The retail provider shall retain the documentation for purposes of verification. If the retail provider cannot document the region of destination for any wholesale sale, the region of destination shall be designated as unknown. Wholesale sales designated with unknown destinations shall be reported as an export under section 95111(b)(2)(D-E).

(J) Wholesale sales (MWh) of power purchased or taken from specified facilities operated by the retail provider delivered to point of delivery inside California and the designation of the region of destination as CAISO pooled real-time market, CAISO pooled integrated forward market, or California.

(K) Wholesale sales (MWh) of power purchased or taken from specified sources not operated by the retail provider delivered to point of delivery inside California and the designation of the region of destination as CAISO pooled real-time market, CAISO pooled integrated forward market, or California.

(L) Wholesale sales (MWh) from power purchased or taken unspecified sources to counterparties inside California and the designation of the region of destination as CAISO pooled real-time market, CAISO pooled integrated forward market, or California.

(M) If the retail provider holds a contract that entitles the retail provider to a specified percentage of a facility's generation in the report year, the retail provider shall include power purchased or sold from that facility as being from a partially owned facility.

(N) ***Ownership Share Differential.*** Retail providers shall report the following information for facilities that are fully or partially owned by the retail provider and that have CO_2 emissions greater than 1,100 lbs of CO_2 per MWh based on the most recent verified greenhouse gas emissions data report or on CO_2 emissions reported to U.S.EPA under 40 CFR Part 75.

1. Facility name, ARB designated facility ID, and generating unit ID as applicable
2. Percent ownership share at the facility level and ownership share at the unit level as applicable
3. By facility or generating unit as applicable the amount of power to be called the "ownership share differential" that is calculated as follows:

$$OSD_{MWh,i} = 0.9(OS_i)(NG_{MWh,i}) - GF_{MWh,i}$$

Where:
$OSD_{MWh,i}$ = power ownership share differential for facility i, MWh per year
OS_i = ownership share of facility i, percentage expressed as a value from 0-1 (e.g., 50% = 0.5)
$NG_{MWh,i}$ = total net generation of facility i, MWh per year
$GF_{MWh,i}$ = net generation taken from facility i, MWh per year

(O) For retail providers that report a positive ownership share differential from a facility in section 95111(b)(3)(N), the retail provider shall specify the amount of wholesale sales (MWh) made by the retail provider or on behalf of the retail provider from the facility to counterparties located outside California that meets either one of the following criteria and shall retain documentation for verification purposes.

1. The power could not be delivered to the reporting entity during the hours in which it was sold due to congestion in the transmission and distribution system or similar issues;
2. The retail provider did not need the power during the hours in which it was sold for reasons not related to reducing the retail provider's greenhouse gas emissions responsibility. Reasons may include, but are not limited to, that the retail provider's own load was met by resources that were less expensive than the specified facility (excluding any value associated with greenhouse gas mitigation).

(P) ***Adjusted Ownership Share Differential.*** Retail providers that report a positive ownership share differential in section 95111(b)(3)(N) shall report the difference in this amount of power and the amount of wholesale sales that meet the criteria in section 95111(b)(3)(O). The difference shall be called the "adjusted ownership share differential". The adjusted ownership share differential may be reduced further as specified in section 95111(b)(3)(Q).

(Q) Retail providers that report a positive adjusted ownership share differential in section 95111(b)(3)(P) for a specified facility may retain

for purposes of verification, documentation that the facility reduced operations as a result of a reduced demand for power by the retail provider. The retail provider may reduce the adjusted ownership share differential by the amount of power generation that was reduced.

(R) For facilities fully or partially owned by the retail provider not reported in section 95111(b)(3)(N), include facility name, ARB designated facility ID, generating unit ID as applicable, percent ownership share at the facility level, and ownership share at the generating unit level as applicable.

(S) The retail provider may elect to report retail sales related to the electrification of shipping ports, truck stops, and other motor vehicles if metering is available to separately track these sales from other retail sales.

(c) ***Calculation of CO_2 Emissions from Fuel Combustion***. Operators of generating facilities, retail providers, and marketers shall meet the following requirements in preparing CO2 emission calculations from fuel combustion for inclusion in the greenhouse gas emissions data report.

(1) ***Natural Gas.*** Operators of generating facilities that combust natural gas and are subject to the requirements of 40 CFR Part 75 shall include Part 75 CO_2 emissions data for the report year. Operators may elect to use revenue fuel meters to conduct quality checks on generating unit level information. For facilities that combust natural gas but are not required to report CO_2 emissions under 40 CFR Part 75, the operator shall calculate and include CO_2 emissions using methodologies provided in:

(A) Sections 95125(c-d) or (g) if the high heat value is $\geq$ 975 and $\leq$ 1100 Btu per scf or;

(B) Section 95125(d) or (g) if the high heat value is < 975 or > 1100 Btu per scf.

(2) ***Coal or Petroleum Coke.***

(A) Operators of facilities that combust coal or petroleum coke and are subject to the requirements of 40 CFR Part 75 shall include Part 75 CO_2 emissions data for the report year, or CO_2 emissions based on alternative equations and specifications by fuel type provided in 40 CFR Part 75, Appendix G;

(B) If the facility is not subject to the requirements in 40 CFR Part 75, the operator of the generating facility shall calculate and include CO_2

emissions using methods specified in section 95125(d) or section 95125(g).

(3) ***Middle distillates, gasoline, residual oil, or liquid petroleum gases (LPG).***

(A) If a facility combusts middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-Butane, or unspecified LPG) and is subject to the requirements of 40 CFR Part 75, the operator of the facility shall include Part 75 CO_2 emissions data for the report year;

(B) If the facility is not subject to the requirements of 40 CFR Part 75, the operator shall calculate and include annual CO_2 emissions using the methods specified in sections 95125(c-d) or (g).

(4) ***Refinery Gas, Still Gas, Process Gas, or Associated Gas.*** If a generating facility combusts refinery gas, still gas, process gas, or associated gas, the operator shall calculate and include CO_2 emissions for the report year using the methods specified in section 95125(e) or 95125(g).

(5) ***Landfill Gas or Biogas.*** If a facility combusts landfill gas or biogas from derived from biomass, the operator shall calculate and include CO_2 emissions for the report year using the method specified in section 95125(c), 95125(d), or 95125(g).

(6) ***Biomass or Municipal Solid Waste.*** If a facility combusts biomass or municipal solid waste, the operator shall calculate and include CO_2 emissions for the report year based on methodologies provided in section 95125(g) based on continuous emission monitoring systems, CO_2 concentrations, and flue gas flow rates. If the facility does not have appropriate devices to measure CO_2 concentrations and flue gas flow rates, then the operator of the facility shall use methods specified in section 95125(h).

(7) ***CO_2 Emissions for Fuels Co-Fired.*** Operators shall use the following methodologies to determine separately and include CO_2 emissions from fuels (excluding refinery gases) that are co-fired at a facility.

(A) If more than one fossil fuel is co-fired in a facility that does not report using data from a continuous emissions monitoring system, then CO_2 emissions shall be calculated separately for each fuel type using methods specified in section 95111(c) by fuel type. Operators who have the option in this article to calculate emissions based on data from a continuous emissions monitoring system, and who co-fire more

than one fossil fuel, need not report emissions separately for each fossil fuel.

(B) If a biomass-derived fuel is co-fired with a fossil fuel in a facility and the operator does not report CO_2 emissions using data from a continuous emissions monitoring system, then CO_2 emissions shall be calculated separately for each fuel type using methods specified in section 95111(c) by fuel type. If the facility does have a continuous emissions monitoring system, then the operator shall calculate emissions associated with each fuel using the methods specified in section 95125(g)(4).

(8) ***Start-Up Fuels***. The operators of generating facilities that primarily combust biomass-derived fuels but that combust fossil fuels for start-up, shut-down, or malfunction operating periods only, shall calculate and include CO_2 emissions from fossil fuel combustion using methodologies in section 95125(a) or methods specified in section 95111(c) by fuel type.

(d) ***Calculation of N_2O and CH_4 from Fuel Combustion.*** Operators of generating facilities, retail providers, and marketers shall use the methodologies provided in section 95125(b) to calculate and include N_2O and CH_4 emissions from fuel combustion.

(e) ***Calculation of CO_2 Process Emissions from Acid Gas Scrubbing.*** Operators that use acid gas scrubbers or add an acid gas reagent to the combustion source shall include CO_2 emissions from these processes if these emissions are not already captured in CO_2 emissions calculations based on a continuous emissions monitoring system. The operator shall calculate CO_2 emissions from the acid gas processes using the following equation:

$$CO_2 = S * R * (CO_{2\ MW} / Sorbent_{\ MW})$$

Where:
CO_2 = CO_2 emitted from sorbent for the report year, metric tonnes;
S = Limestone or other sorbent used in the report year, metric tonnes;
R = Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\ MW}$ = molecular weight of carbon dioxide (44);
$Sorbent_{\ MW}$ = molecular weight of sorbent (if calcium carbonate, 100).

(f) ***Determining Fugitive SF_6 Emissions.*** Operators of generating facilities, retail providers, and marketers shall use the methodology provided by the U.S. EPA SF_6 Emission Reduction Partnership for Electric Power Systems to determine fugitive SF_6 emissions as specified in Appendix A. The operator shall convert pounds of SF_6 into kilograms.

(g) ***Determining Fugitive HFC Emissions.*** Operators of generating facilities shall calculate fugitive HFC emissions from cooling units used in support to power generation or used in heat transfers used to cool stack gases using the methodology provided by U.S. EPA SF_6 Emission Reduction Partnership but substituting HFCs for SF_6 in the methodology. The operator shall convert pounds of HFCs into kilograms. This section does not apply to air or water cooling systems or condensers that do not contain HFCs.

(1) Operators who are reporting by individual cooling unit may elect to use service logs to record measurements of HFCs added to the unit. Service logs shall include measurements for all applications during the report year, including a record at the beginning and ending of each year.

(h) ***Calculation of Fugitive CH_4 Emissions.*** Operators for generating facilities that combust coal shall calculate and include fugitive CH_4 emissions from coal storage using the methodology provided in section 95125(j).

(i) ***Calculation of Fugitive CO_2 Emissions from Geothermal Generating Facilities.*** Operators of geothermal electric generating facilities shall calculate and include fugitive CO_2 emissions using one of the following methods:

(1) $CO_2 = EF * Heat * (0.001)$

Where
CO_2 = CO_2 emissions, metric tonnes per year;
EF = Default fugitive CO_2 emission factor for geothermal facilities as specified in Appendix A, kg per MMBtu;
Heat = Heat taken from geothermal steam and/or fluid, MMBtu per year.

(2) Operators of geothermal generating facilities may calculate CO_2 emissions using a source specific emission factor derived from source tests conducted under the supervision of local air pollution control districts/air quality management districts and approved by ARB. Once the source test plan has been approved by ARB, the source test procedures shall be repeated in future years to update the source specific emission factors annually. In the absence of source specific emission factors approved by ARB, the operator shall use the method specified above in 95111(i)(1).

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95112. Data Requirements and Calculation Methods for Cogeneration Facilities.

(a) ***Greenhouse Gas Emissions Data Report.*** The operator of a cogeneration facility subject to the requirements of this article shall include the following information in the greenhouse gas emissions data report for each report year.

(1) Facility level and generating unit information as specified in sections 95111(a)(1)-(3) as applicable.

(2) Cogeneration System:
  (A) Prime mover of each cogeneration system.

(3) Electricity Generation:
  (A) Electricity sold wholesale (MWh)
  (B) Electricity sold or provided to off-site end-users (MWh)
    1. User's NAICS code
  (C) Electricity consumed on-site for each report year (MWh)

(4) Thermal Energy Production:
  (A) Useful thermal output (MMBtu)
  (B) Amount of thermal energy sold or provided to off-site end-users (MMBtu)
    1. User's NAICS code
  (C) Amount of thermal energy consumed on-site for processes other than the cogeneration system for each report year (MMBtu)
  (D) Output of heat recovery steam generator (HRSG) (MMBtu)
  (E) Fuel fired for supplemental firing in the duct burner of the HRSG (MMBtu)
  (F) Efficiency of HRSG (percent)

(5) Distributed Emissions:
  (A) Distributed emissions to thermal energy production (metric tonnes CO_2)
  (B) Distributed emissions to electricity generation (metric tonnes CO_2)
    1. Efficiency of electricity generation (percent)
    2. Total fuel input (MMBtu)
  (C) Distributed emissions to manufactured product outputs, as applicable (metric tonnes CO_2)

(6) Indirect electricity usage as specified in section 95125(k).
  (A) Electricity purchased and consumed (kWh)
  (B) Electricity provider (Name)

(b) ***Calculation of CO_2, N_2O, and CH_4 Emissions.*** Operators of cogeneration facilities shall calculate emissions for each source specified in this section.

(1) CO_2 emissions from stationary combustion using methodologies listed by fuel type for electric generating facilities as specified in section 95111(c).

(2) GHG emissions from processes and from fugitive sources as specified for electric generating facilities in sections 95111(e)-(h), if applicable, using the methodologies designated in the respective sections.

(3) N_2O and CH_4 emissions from stationary combustion using the methodologies provided in section 95125(b).

(4) **Distributed Emissions.** Topping cycle plant operators shall calculate distributed emissions for electricity generation and thermal energy production separately using the Efficiency Method provided in section 95112(b)(4)(A). Bottoming cycle plant operators shall calculate and report distributed emissions for electricity generation, thermal energy production, and manufactured product outputs using the Detailed Efficiency Method provided in section 95112(b)(4)(B).

(A) Distributed Emissions for Topping Cycle Plants: Operators shall calculate distributed emissions using the Efficiency Method equations specified in this section, 95112(b)(4)(A). Topping cycle plant operators shall calculate emissions distributed to thermal energy production using a facility-specific electricity generation efficiency value as specified in section 95112(b)(4)(A)1. or an assumed 0.35 average value for electricity efficiency. Operators shall calculate distributed emissions using an assumed 0.80 average value or use the Heat Recovery Steam Generator (HRSG) or boiler manufacturers rating for the thermal energy production efficiency (e_H) value. Operators shall distribute emissions to electricity generation by subtracting distributed emissions to thermal energy production from CO_2 emissions from stationary combustion for the report year.

Efficiency Method

Thermal Energy Production

$$E_H = \frac{H / e_H}{H / e_H + P / e_P} \times E_T$$

Electricity Generation

$$E_P = E_T - E_H$$

Where:

E_H = Distributed emissions to thermal energy production, metric tonnes CO_2

H = Useful thermal output for the report year, MMBtu

e_H = Efficiency of thermal energy production

P = Annual net power generated, MMBtu (MWh x 3.413) = MMBtu
e_P = Efficiency of electricity generation
E_T = CO_2 emissions from stationary combustion in the report year, metric tonnes CO_2
E_P = Distributed emissions to electricity generation, metric tonnes CO_2

1. *Facility-Specific Electricity Generation Efficiency Value:*

$$e_P = \frac{P}{F}$$

Where:
e_P = Efficiency of electricity generation
P = Net power generated in the report year, MMBtu
F = Total Fuel Input, MMBtu

(B) Distributed Emissions for Bottoming Cycle Plants: Operators shall calculate distributed emissions using the Detailed Efficiency Method equations specified in this section, 95112(b)(4)(B). Bottoming cycle plant operators shall calculate emissions from stationary combustion for the manufacturing process as specified in section 95112(b)(4)(B)2. Operators shall use assumed values of 0.80 for thermal energy and 0.35 for electricity efficiency. Operators may also report emissions using a calculated facility-specific electricity generation efficiency value as specified in section 95112(b)(4)(B)1 or use the Heat Recovery Steam Generator (HRSG) or boiler manufacturers rating for the thermal energy production efficiency (e_H) value. Operators shall distribute emissions to electricity generation by subtracting distributed emissions to thermal energy production and manufactured product from CO_2 emissions from fuel combustion for the report year.

Detailed Efficiency Method

Thermal Energy Production

$$E_H = \frac{H/e_H}{H/e_H + P/e_P} \times (E_T - E_M)$$

Electricity Generation

$$E_P = E_T - E_H - E_M$$

Where:
E_H = Distributed emissions to thermal energy production, metric tonnes CO_2
H = Useful thermal output for the report year, MMBtu
e_H = 0.80 = Efficiency of thermal energy production
P = Net power generated for the report year, MMBtu (MWh x 3.413) = MMBtu
e_P = Efficiency of electricity generation

E_T = CO_2 emissions from stationary combustion in the report year, metric tonnes

E_M = Distributed emissions to manufacturing product, metric tonnes CO_2, computed as specified in section 95112(b)(4)(B)2.

E_P = Distributed emissions to electricity generation, metric tonnes CO_2

1. *Facility-Specific Electricity Generation Efficiency Value:*

$$e_P = \frac{P}{(F + H_e)}$$

Where:

e_P = Efficiency of electricity generation

P = Net power generated in the report year, MMBtu

F = Total Fuel input, MMBtu

He = Exothermic heat from manufacturing process, MMBtu, computed as specified in section 95112(b)(4)(B)3.

2. *Emissions Assigned to Manufacturing Process:*

$$E_M = E_T\left[1 - \frac{P + H + F_S \times (1 - HRSG_{EF})}{F + H_e}\right]$$

Where:

E_M = Distributed emissions to manufacturing product, metric tonnes CO_2

E_T = Emissions from stationary combustion in the report year, metric tonnes CO_2

P = Annual net power generated, MMBtu (MWh × 3.413) = MMBtu

H = Useful thermal output in the report year, MMBtu

F = Total Fuel Input, MMBtu

F_S = Supplemental Firing of Fuel Fired in Duct Burner of HRSG, MMBtu

H_e = Exothermic heat from manufacturing process, MMBtu, computed as specified in section 95112(b)(4)(B)3.

$HRSG_{EF}$ = Efficiency of HRSG, use 0.8 as a default if actual efficiency is unknown

H_e shall only be included if an exothermic manufacturing process is used.

3. *Exothermic Heat from Manufacturing Process*

$$He = \frac{HRSG}{HRSG_{EF}} - F$$

Where:

H_e	=	Exothermic heat from manufacturing process, MMBtu
HRSG	=	Output of heat recovery steam generator in the report year, MMBtu
$HRSG_{EF}$	=	Efficiency of HRSG, use 0.8 as a default if actual efficiency is unknown
F	=	Total Fuel Input, MMBtu

If H_e value calculated above is negative, then the exothermic heat of the process is not sufficient to overcome the process use and/or loss of the input fuel heat and the H_e value is then set to 0.

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95113. Data Requirements and Calculation Methods for Petroleum Refineries.

(a) ***Greenhouse Gas Emissions Data Report.*** The operator of a petroleum refinery shall include the following information in the greenhouse gas emissions data report for each report year from facility emission sources as specified:

(1) ***Stationary Combustion – CO_2 Emissions by Fuel Type.***

(A) Refinery Fuel Gas: CO_2 emissions resulting from the combustion of refinery fuel gas as specified in section 95125(e), (metric tonnes).

(B) Natural Gas: CO_2 emissions resulting from the combustion of natural gas as specified in section 95125(c) or (d), (metric tonnes).

(C) Fuel Mixtures: CO_2 emissions resulting from the combustion of each fuel contained in the fuel mixture or for each fuel mixture as specified in section 95125(f), (metric tonnes).

(D) Other Fuels: CO_2 emissions resulting from the combustion of No. 1, No. 2, No 4, No. 5, and No. 6 fuels, kerosene, residual oil, distillate oil, gasoline, diesel fuel, and LPG using the methods specified in section 95125(a), (metric tonnes).

(2) ***Stationary Combustion – CH_4 and N_2O.*** Emissions from stationary combustion sources using methods specified in section 95125(b), (metric tonnes).

(3) ***Fuel Consumption.*** Fuel consumption by fuel type in the report year (including petroleum coke) (scf, gallons, or ton)

(4) ***Hydrogen Production Plant Emissions.*** The operator shall calculate emissions using the methodologies specified in section 95114, (metric tonnes).

(5) ***Process Emissions.*** The operator shall calculate process emissions using the methodologies in section 95113(b), (metric tonnes).

(6) ***Fugitive Emissions.*** The operator shall calculate process emissions using the methods specified in section 95113(c), (metric tonnes).

(7) ***Flaring Emissions.*** The operator shall calculate flaring emissions using the methods specified in section 95113(d), (metric tonnes)

(8) ***Cogeneration Emissions.*** Operators of refineries with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(9) ***Indirect Energy Purchases.*** The operator shall calculate indirect energy purchased and consumed using methods specified in section 95125(k)-(l).

(b) ***Calculation of Process Emissions.*** The operator shall calculate process emissions as specified in this section.

(1) Catalytic Cracking

(A) Operators shall calculate and report CO_2 emissions from the regeneration of catalyst material using the methods specified below in section 95113(b)(1)(A), (B), (C) and (D). These methods shall be applied to fluid catalytic cracking units, fluid cokers, catalytic reforming units including but not limited to those engaged in semi-regenerative, cyclic or continuous catalyst regeneration. Hourly coke burn rate shall be calculated as shown below:

$$CR = K_1Q_r(\%CO_2 + \%CO) + K_2Q_a - K_3Q_r[\%CO/2 + \%CO_2 + \%O_2] + K_3Q_{oxy}(\%O_{xy})$$

Where:

CR = coke burn rate (kg/hr)
K_1, K_2, K_3 = material balance and conversion factors (K_1, K_2, and K_3 - see Appendix A)
Q_r = volumetric flow rate of exhaust gas before entering the emission control system (dscm/min)
Q_a = volumetric flow rate of air to regenerator as determined from control room instrumentation (dscm/min)
$\%CO_2$ = percent CO_2 concentration in regenerator exhaust, percent by volume – dry basis
%CO = percent CO concentration in regenerator exhaust, percent by volume – dry basis
$\%O_2$ = percent oxygen concentration in regenerator exhaust, percent by volume – dry basis
Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation (dscm/min)
$\%O_{xy}$ = O_2 concentration in O_2 enriched air stream inlet to regenerator, percent by volume – dry basis

Q_r shall be determined in the following manner:

$$Q_r = 79 * Q_a + (100- \%Q_{oxy}) \times Q_{oxy}/100 - \%CO_2 - \%CO - \%O_2$$

Where:

Q_r = volumetric flow rate of exhaust gas from regenerator before entering the emission control system (dscm/min)
Q_a = volumetric flow rate of air to regenerator, as determined from control room instrumentation (dscm/min)

Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation (dscm/min)
$\%CO_2$ = carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis
%CO = carbon monoxide concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero
$\%O_2$ = O_2 concentration in regenerator exhaust, percent by volume – dry basis

(B) Operators shall calculate a daily average coke burn rate (CR_d) for each day of operation as the sum of hourly coke burn rate determinations for each hour of operation divided by the number of operational hours per day.

(C) Operators shall calculate and report CO_2 emissions as shown below:

$$CO_2 = \sum_{0}^{n} CR_d * CF * 3.664 * 0.001$$

Where:
CO_2 = CO_2 emissions (metric tonnes/yr)
n = number of days of operation in the report year
CR_d = daily average coke burn rate (kg/day)
CF = carbon fraction in coke burned (default = 1)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

(2) Periodic Catalyst Regeneration

(A) Operators shall calculate and report process CO_2 emissions resulting from periodic catalyst regeneration as shown below.

$$CO_2 = \sum_{1}^{n} CR_{ave} * CF * H * 3.664 * 0.001$$

Where:
CO_2 = CO_2 emissions (metric tonnes/yr)
CR_{ave} = mass of catalyst regenerated (mass/regeneration cycle)
CF = weight fraction of carbon on the catalyst (default = 1)
n = number of regeneration cycles (#/yr)
0.001 = conversion factor – kg to metric tonnes

(3) Process Vents

(A) Operators shall calculate and report process emissions of CO_2, CH_4, and N_2O using the method shown below. Process emissions calculated and reported using other methods specified in this regulation shall not be calculated and reported here.

$$E_x = \sum_{1}^{n} VR * F_x * MW_x/MVC * VT * 0.001$$

Where:

E_x = emissions of x (metric tonnes/yr)
(x = CO_2, N_2O, CH_4)
VR = vent rate (scf/unit time)
F_x = molar fraction of x in vent gas stream
MW_x = molecular weight of X (kg/kg-mole)
MVC = molar volume conversion (849.5 scf/kg-mole)
VT = time duration of venting
n = number of venting events
0.001 = conversion factor – kg to metric tonnes

(4) Asphalt Production

(A) Operators shall calculate and report CO_2 and CH_4 emissions resulting from asphalt bowing activities (where these emissions are not reported to the local AQMD/APCD and subsequently reported as directed in section 95113(f)) using the method specified below:

$$CH_4 = (Ma * EF * MW_{CH4}/MCV)(1 - DE) * 0.001$$

Where:

CH_4 = CH_4 emissions (metric tonnes/yr)
M_A = mass of asphalt blown (10^6 bbl/yr)
EF = default emission factor (2,555 scf $CH_4/10^6$ bbl)
MW_{CH4} = CH_4 molecular weight (16 kg/kg-mole)
MVC = molar volume conversion factor (849.5 scf/kg-mole)
DE = control measure destruction efficiency (default = 98% expressed as 0.98)
0.001 = conversion factor – kg to metric tonnes

$$CO_2 = (Ma * EF * MW_{CH4}/MCV) * DE * 2.743 * 0.001$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)
M_A = mass of asphalt blown (10^6 bbl/yr)
EF = default emission factor (2,555 scf $CH_4/10^6$ bbl)
MW_{CH4} = CH_4 molecular weight (16 kg/kg-mole)
MVC = molar volume conversion factor (849.5 scf/kg mole)
DE = control measure destruction efficiency (default = 98% expressed as 0.98)
2.743 = CH_4 to CO_2 conversion factor
0.001 = conversion factor – kg to metric tonnes

(5) Sulfur Recovery

(A) Operators shall calculate CO_2 process emissions from sulfur recovery units (SRU) using the methods specified below:

$$CO_2 = FR * MW_{CO2}/MVC * MF * 0.001$$

Where:

CO_2 = emissions of CO_2 (metric tonnes/yr)
FR = volumetric flow rate to SRU (scf/year)
MW_{CO2} = molecular weight of CO_2 (44 kg/kg-mole)
MVC = molar volume conversion (849.5 scf/ kg-mole)
MF = molecular fraction of CO_2 in sour gas (default = 0.20)
0.001 = conversion factor – kg to metric tonnes

(B) As an alternative to using the default emission factor, the operator may elect to calculate CO_2 emissions using ARB approved source specific emission factors derived from source tests conducted at least per calendar year under the supervision of ARB or the local air pollution control district or air quality management district. Upon approval of a source test plan by ARB, the source test procedures in that plan shall be repeated in future years to update the source specific emission factors annually. In the absence of source specific emission factors approved by ARB, the operator shall use the default emission factors provided by ARB.

(c) ***Calculation of Fugitive Emissions.*** The operator shall calculate fugitive emissions as specified in section 95113(c).

(1) Wastewater Treatment – CH_4 and N_2O

(A) Operators shall calculate methane emissions from wastewater treatment as shown below:

$$CH_4 = [(Q * COD) - S] * B * MCF * 0.001$$

Where:

CH_4 = emission of methane (tonnes/yr)
Q = volume of wastewater treated (m^3/yr)
COD_{qave} = average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3)
S = organic component removed as sludge (kg COD/yr)
B = methane generation capacity (default = 0.25 kg CH_4/kg COD)
MCF = methane conversion factor for the anaerobic decay (0-1.0) consult Table provided in Appendix A
0.001 = conversion factor – kg to metric tonnes

(B) Operators shall calculate and report nitrous oxide emissions from wastewater treatment as shown below:

$$N_2O = Q * N_{qave} * EF_{N2O} * 3.142 * 0.001$$

Where:

N_2O = emissions of N_2O (metric tonnes/yr)
N_{qave} = average of quarterly determinations of N in effluent (kg N/m^3) nitrogen content of effluent (kg N/yr)
EF_{N2O} = emission factor for N_2O from discharged wastewater (kg N_2O-N/kg N) (default = 0.005)
3.142 = conversion factor – kg N_2O-N to kg N_2O
0.001 = conversion factor – kg to metric tonnes

(2) Oil-Water Separators – Operators shall calculate emissions from oil-water separators as shown below.

$$CH_4 = F_{sep} * V_{water} * CF_{NMHC} * 0.001$$

Where:

CH_4 = emission of methane (tonnes/yr)
F_{sep} = NMHC (non methane hydrocarbon) emission factor (kg/m^3) see Table in Appendix A.

V_{water} = volume of waste water treated by the separator (m^3/yr)
CF_{NMHC} = NMHC to CH_4 conversion factor (default = 0.6)
0.001 = conversion factor – kg to metric tonnes

(3) Storage Tanks
(A) Operators shall calculate CH_4 emissions from crude oil, naphtha, distillate oil, asphalt, and gas oil storage tanks using the U.S. EPA TANKS Model (Version 4.09D).

(4) Equipment Fugitive Emissions
(A) Operators shall calculate CH_4 fugitive emissions for all gas service components as specified in CAPCOA (1999) Method 3: Correlation Equation Method in the following manner:

1. Screening values (SV) for all components comprising all natural gas, refinery fuel gas, process gas, and PSA off-gas systems shall be recorded and identified as one of the following component leak categories 1) default zero components, 2) components where the SV is above background but below 10,000 ppm, 3) pegged source components (SV greater than 10,000 ppm but less than 100,000 ppm or 4) pegged source components where the SV is greater than 100,000 ppm. Components will be characterized as one of the following 1) valves, 2) pump seals, 3) connectors, 4) flanges, 5) open-ended lines or 6) others (component types other than 1-5). Operators shall use the Component Identification and Counting Methodology found in CAPCOA (1999), which is incorporated by reference herein.

2. VOC emissions for each of the four leak categories shall be calculated in the following manner:

For Zero components use the following equation:

$$E_{VOC\text{-}0} = \sum_{1}^{n} CC_i * RF_{i0}$$

Where:
$E_{VOC\text{-}0}$ = VOC emission rate for all zero components (kg/hr)
n = total number of zero components
CC_i = component count (i= values, pump seals, connectors, flanges, open-ended lines, others)
RF_{i0} = default VOC emission factor for zero component i (kg/hr) (see Table in Appendix A.)

For SV > Bkgd and SV <10,000 ppmv components use the following equation:

$$E_{VOC\text{-}L} = \sum_{1}^{n} C_{ief} * SV^{\beta}$$

Where:

$E_{VOC\text{-}L}$ = VOC emission rate – leaking components (kg/hr)
C_{ief} = component i correlation equation constant
n = total number of components in this class
SV = screening value (ppmv)
β = correlation equation exponent (see Table in Appendix A)

For 10K Pegged components (SV > 10,000 ppmv, SV <100,000 ppmv) components use the following equation:

$$E_{VOCP\text{-}10} = \sum_{1}^{n} CC_i * RF_{iP10}$$

Where:

$E_{VOCP\text{-}10}$ = VOC emission rate – 10K pegged components (kg/hr)
CC_i = component count (i= values, pump seals, connectors, flanges, open-ended lines, others)
n = total number of components in this class
RF_{iP10} = default VOC emission factor for component i pegged above 10,000 ppmv but below 100,000 ppm (see Table in Appendix A)

For 100K Pegged components (SV > 100,000 ppmv) components use the following equation:

$$E_{VOCP\text{-}100} = \sum_{1}^{n} C_{ief} * RF_{iP\text{-}100}$$

Where:

$E_{VOCP\text{-}100}$ = VOC emission rate – 100 K pegged components (kg/hr)
C_{ief} = component i correlation equation constant
n = total number of components in this class
$RF_{iP\text{-}100}$ = default VOC emission factor for component i pegged above 100,000 ppmv. (see Table in Appendix A)

3. Methane emissions shall be calculated in the following manner:

$$CH_4 = (E_{VOC\text{-}0} + E_{VOC\text{-}L} + E_{VOCP\text{-}10} + E_{VOCP\text{-}100}) * t * CF_{VOC} * 0.001$$

Where:

CH_4 = methane emissions (metric tonnes /yr)
t = hours/yr components were pressurized (default = 8,760 hrs)
CF_{VOC} = default VOC to CH_4 conversion factor = 0.6
0.001 = conversion factor – kg to metric tonnes

(d) ***Calculation of Flaring Emissions.***

(1) Operators shall calculate CO_2 emissions resulting from the combustion of flare pilot and purge gas using the method shown below:

$$CO_2 = \sum_{1}^{n} CC * FR * FE * MW_{CO2}/MVC * 0.001$$

Where:

CO_2 = emissions of CO_2 (metric tonnes/yr)
CC = carbon content of the fuel (mole percent)
FR = fuel flow rate (scf/yr)
FE = flare destruction efficiency (%)
MW_{CO2} = molecular weight of CO_2 (44 kg/kg-mole)
MVC = molar volume conversion (849.5 scf/ kg-mole)
0.001 = conversion factor – kg to metric tonnes

The carbon content of natural gas combusted as flare pilot and purge gas will be measured monthly by the refiner.

(2) Operators shall calculate and report CO_2 (and CH_4 where applicable) emissions resulting from the combustion of hydrocarbons routed to flares for destruction using one of the methods specified below:

(A) Operators reporting CH_4 and NMHC emissions to their local Air Quality Management District shall calculate CO_2 emissions as follows:

$$CO_2 = \sum_{1}^{365} [CF_{NMHC} * NMHC * 1/(1\text{-}FE) * 3.664 + (CH_4 * 1/(1\text{-}FE)) * 2.746] * 0.001$$

Where:

CO_2 = emissions of CO_2 (metric tonnes/yr)
CF_{NMHC} = carbon fraction in NMHC (0.6 default value)
NMHC = flare non-methane hydrocarbon emissions (kg/day)
CH_4 = flare methane emissions (kg/day)
FE = flare destruction efficiency (%)
2.746 = conversion factor – methane to carbon dioxide

0.001 = conversion factor – carbon to carbon dioxide

Operators shall use the following flare destruction efficiencies (FE):

Gas combusted HHV > 200 Btu/scf FE = 98%
Gas combusted HHV < 200 Btu/scf FE = 93%

Operators shall calculate and report the sum of all flare CH_4 emissions reported to the local AQMD/APCD for the report year (metric tonnes/yr)

(B) Operators subject to Rule 1118 – Control of Emissions from Refinery Flares (South Coast Air Quality Management District) shall calculate ROG as specified in Attachment B of Rule 1118, which is incorporated by reference herein, and report flare CO_2 emissions as follows:

$$CO_2 = \sum_{1}^{365} (CF_{ROG} * [ROG * 1/(1-FE)] * 3.664) * 0.001$$

Where:

CO_2 = emissions of CO_2 (metric tonnes/yr)
CF_{ROG} = carbon fraction in ROG (0.6 default value)
ROG = reactive organic gas flare emissions (kg/day)
FE = flare destruction efficiency (%)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

Operators shall use the following flare destruction efficiencies (FE):

Gas combusted HHV > 200 Btu/scf FE = 98%
Gas combusted HHV < 200 Btu/scf FE = 93%

(C) Operators not reporting flare emissions to their local AQMD/APCD shall use a default emission factor to calculate CO_2 emissions as shown below:

$$CO_2 = EF_{CO2} * RT$$

Where:

CO_2 = CO_2 emissions (metric tonnes/year)
EF_{CO2} = default CO_2 emission factor (tonnes $CO_2/10^6$ barrels crude)
RT = refinery throughput (10^6 barrels crude /year)

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95114. Data Requirements and Calculation Methods for Hydrogen Plants.

(a) ***Greenhouse Gas Emissions Data Report.*** The operator of a hydrogen production facility that emits greater than or equal to 25,000 metric tonnes per year of CO_2 from the combination of stationary combustion sources and hydrogen production processes shall report emissions of CO_2, CH_4 and N_2O from the facility. The operator shall include in the emissions data report for each report year the information required by this section, using the methods specified.

(1) ***Fuel and Feedstock Consumption.*** Fuel and feedstock consumption in the report year by fuel/feedstock type (including petroleum coke) (scf, gallons, or ton).

(2) ***Production.*** Operators shall report the total hydrogen produced at the facility in the report year (scf) and the amount of hydrogen sold for use as transportation fuel (scf).

(3) ***Stationary Combustion – CH_4 and N_2O.*** The operator shall calculate CH_4 and N_2O emissions from stationary combustion sources using methods specified in section 95125(b), (metric tonnes).

(4) ***Fugitive Emissions.*** The operator shall calculate fugitive emissions using the methods specified in section 95113(c), (metric tonnes).

(5) ***Flaring Emissions.*** The operator shall calculate emissions resulting from flaring (if these emissions are not calculate using other methods specified ion this regulation) using the methods specified in section 95113(d), (metric tonnes).

(6) ***Transferred CO_2.*** The operator shall calculate the amount of CO_2 sold as transferred carbon dioxide, (metric tonnes). Transferred carbon dioxide shall not be subtracted from total CO_2 emissions reported.

(7) ***Process Vent Emissions.*** The operator shall report process vent emissions not reported using other methods specified in this regulation as specified in section 95113(b)(3), (metric tonnes)

(8) ***Sulfur Recovery Process Emissions.*** The operator shall report CO_2 process emissions from sulfur recovery units as specified in section 95113(b)(5), (metric tonnes).

(9) ***Cogeneration Emissions.*** Operators of hydrogen plants with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(10) ***Indirect Energy Purchases.*** Operators shall report all indirect energy purchased and consumed as specified in sections 95125(k)-(l).

(11) ***Stationary Combustion and Process CO_2 Emissions.*** Operators shall calculate stationary combustion and process CO_2 emissions as specified in section 95114(b), (metric tonnes).

(b) ***Calculation of CO_2 Stationary Combustion and Process Emissions.*** The operator shall calculate CO_2 stationary combustion and process emissions using one of the methods specified in this section.

(1) ***Continuous Monitoring Systems.*** Hydrogen plant operators may elect to calculate CO_2 process and stationary combustion using Continuous Emissions Monitoring Systems (CEMS) as specified in section 95125(g)(6).

(2) ***Fuel and Feedstock Mass Balance.*** Hydrogen plant operators may elect to calculate CO_2 process and stationary combustion emissions using the method specified below.

$$CO_2 = [\sum_{1}^{x}\sum_{1}^{n} F_i * CF_{Fi} + FS * CF_{FS} - S] * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide process and stationary combustion emissions – metric tonnes/year
x = days of operation per reporting period
n = total number of fuels combusted
F_i = fuel i consumption rate (kg/day)
CF_{Fi} = carbon fraction of fuel I (kg C/kg fuel)
S = carbon fraction accounted for elsewhere (kg C/day)
FS = feedstock supply rate (kg/day)
CF_{FS} = carbon fraction of feedstock (kg C/kg fuel)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

The operator shall limit the application and use of factor S to situations where CO_2 emissions are accounted for using other methods specified in these regulations (for example: an off-gas stream, such as PSA off-gas, diverted to a refinery fuel gas system or flare where emissions are calculated and reported using applicable methods specified in this regulation). The operator shall determine the carbon fraction of all feedstock mixtures daily. The operator shall determine the carbon content of natural gas that is not mixed with another feedstock prior to consumption once per month. The operator shall choose sampling locations in a manner that minimizes bias.

(3) ***Fuel Stationary Combustion and Feedstock Process Emissions.*** Hydrogen plant operators may elect to calculate CO_2 process and stationary combustion emissions using the methods specified below.

(A) Operators shall calculate CO_2 stationary combustion emissions using methods specified in section 95113(a)(1)

(B) Operators shall calculate CO_2 process emissions using the method specified in this section.

$$CO_2 = \sum_{1}^{n} [(FSR * CF) - S] * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide emissions (metric tonnes/yr)
N = number of operational days
FSR = feedstock supply rate (kg/day)
CF = carbon fraction in feedstock (kg C/kg fuel)
S = carbon fraction accounted for elsewhere (kg C/day)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

The operator shall limit the application and use of factor S to situations where CO_2 emissions are accounted for using other methods specified in these regulations (for example: an off-gas stream, such as PSA off-gas, diverted to a refinery fuel gas system or flare where emissions are calculated and reported using applicable methods specified in this regulation). The operator shall determine the carbon fraction of all feedstock mixtures daily. The operator shall determine the carbon content of natural gas that is not mixed with another feedstock prior to consumption once per month. The operator shall choose sampling locations in a manner that minimizes bias.

(4) ***Process Vent Emission.*** Hydrogen plant operators shall report process emissions of CO_2, CH_4 and N_2O using the method specified in section 95113(b)(3). Process vent emissions calculated using other methods specified in this regulation shall not be calculated here.

(5) ***Sulfur Recovery process Emissions.*** Hydrogen plant operators shall report CO_2 process emissions from sulfur recovery units (SRU) using the method specified in section 95113(b)(5).

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95115. Data Requirements and Calculation Methods for General Stationary Combustion Facilities.

(a) ***Emissions data report.*** The operator of any facility within California that emits greater than or equal to 25,000 metric tonnes per year of CO_2 from stationary combustion sources shall submit an emissions data report in cases where these sources are not included in a report submitted to satisfy the requirements of sections 95110, 95111, 95112, 95113 or 95114. The operator shall include the following information in the emissions data report for each report year:

(1) Stationary Combustion emissions:
  (A) Total CO_2 emissions (metric tonnes)
    1. CO_2 emissions from biomass-derived fuels (metric tonnes)
  (B) Total CH_4 emissions (metric tonnes)
  (C) Total N_2O emissions (metric tonnes)

(2) Fuels information:
  (A) Fuel consumption by fuel type (scf, gallons, or metric tonnes)
    1. The operator shall determine and provide consumption of each fuel by direct measurement for the report year. If there are no installed devices for direct measurement of fuel consumption, facilities shall report consumption on the basis of recorded fuel purchase or sales invoices measuring any stock change (measured in million Btu, gallons, standard cubic feet or metric tonnes) using the following equation:

    Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End

  (B) Average annual carbon content by fuel type, if measured or provided by fuel supplier. (kg Carbon/MMBtu)
  (C) Average annual high heat value by fuel type if measured or provided by fuel supplier. (HHV)

(3) Indirect energy usage:
  (A) Electricity purchases from each electricity provider (kWh)
  (B) Steam, heat, and cooling purchases from each energy provider (Btu)

(b) ***Calculation of CO_2 Emissions.*** The operator shall calculate emissions of CO_2 as specified below.

(1) The operator of a crude petroleum or natural gas production facility identified with the NAICS code 211111 shall report CO_2 emissions from

stationary combustion according to the methods specified in sections 95125(c)-(f).

(A) For natural gas, the operator shall use the method specified in section 95125(c) or 95125(d);
(B) For associated gas, still gas, and process gas, the operator shall use the method specified in section 95125(e);
(C) For fuel mixtures, the operator shall apply the method specified in section 95125(f).

(2) For all other facilities, the operator shall measure and report direct CO_2 emissions from stationary combustion using one of the following methods:
(A) Use of a continuous emissions monitoring systems (CEMS) as specified in section 95125(g);
(B) Use of default emission factors as specified in sections 95125(a);
(C) Use of fuel heat content, carbon content and other fuel-specific parameters as specified in section 95125(c), (d), and (h).

(c) ***Calculation of N_2O and CH_4 Emissions.*** The operator shall calculate emissions of N_2O and CH_4 emissions from fuel combustion using the methodologies provided in section 95125(b).

(d) ***Electric Generating Units.*** Operators of general stationary combustion facilities that operate an electric generating unit or units with nameplate generating capacities greater than or equal to 1 MW that emit 2,500 metric tonnes of CO_2 in the report year shall calculate and report those emissions as specified in section 95111. Electricity generators designated as backup generators in a permit issued by an air pollution control district or air quality management district are not subject to this reporting requirement.

(e) ***Cogeneration.*** Operators of general stationary combustion facilities with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(f) ***Indirect En ergy Usage.*** Operators of general stationary combustion facilities shall calculate indirect electricity and thermal energy purchased or acquired and consumed as specified in sections 95125(k)-(l).

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 3. Calculation Methods Applicable to Multiple Types of Facilities

95125. *Additional Calculation Methods.* Operators shall use one or more of the following methods to calculate emissions as required in sections 95110 through 95115.

(a) **Method for Calculating CO_2 Emissions from Fuel Combustion Using Default Emission Factors and Default Heat Content.**

(1) The operator shall use the method in section 95125(a)(2) to calculate CO_2 emissions, applying the default emission factors and default heat content values provided in the Appendix A, for each type of fuel combusted at the facility.

(2) The operator shall calculate each fuel's CO_2 emissions and report them in metric tonnes using the following equation:

$$CO_2 = Fuel * HHV_D * EF_{CO2} * 0.001$$

Where:

CO_2 = CO_2 emissions from a specific fuel type, metric tonnes CO_2 per year

Fuel = Mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year

HHV_D = Default high heat value specified by fuel type supplied by ARB, MMBtu per unit of mass or volume

EF_{CO2} = Default carbon dioxide emission factor supplied by ARB, kg CO_2 per MMBtu

0.001 = Factor to convert kg to metric tonnes

(b) **Method for Calculating CH_4 and N_2O Emissions from Fuel Combustion Using Default Emission Factors.**

(1) The operator shall use the methods in this section to calculate CH_4 and N_2O emissions, applying the default emission factors provided in the Appendix A for each type of fuel, except as provided in section 95125(b)(4). If the operator is required to measure heat content in sections 95110 through 95115, the measured heat content shall be used in the equation in section 95125(b)(2). If the heat content is not measured, the operator shall employ the default heat content values specified in Appendix A by fuel type and the equation specified in section 95125(3).

(2) If the heat content of the fuel is measured, the operator shall calculate each fuel's CH_4 and N_2O emissions and report them in metric tonnes using the following equation:

$$CH_4 \text{ or } N_2O = \sum_{1}^{n} Fuel_P * HHV_P * EF * 0.001$$

Where:

CH_4 or N_2O = combustion emissions from specific fuel type, metric tonnes CH_4 or N_2O per year

n = Period/frequency of heat content measurements over the year (e.g. monthly n = 12)

$Fuel_P$ = Mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time

HHV_P = High heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume

EF = Default carbon dioxide emission factor supplied by ARB, kg CH_4 or N_2O per MMBtu

0.001 = Factor to convert kg to metric tonnes

(3) If the heat content of the fuel is <u>not</u> measured, the operator shall calculate each fuel's CH_4 and N_2O emissions and report them in metric tonnes using the following equation:

$$CH_4 \text{ or } N_2O = Fuel * HHV_D * EF * 0.001$$

Where:

CH_4 or N_2O = CH_4 or N_2O emissions from a specific fuel type, metric tonnes CH_4 or N_2O per year

Fuel = Mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year

HHV_D = Default high heat value specified by fuel type supplied by ARB, MMBtu per unit of mass or volume

EF = Default emission factor supplied by ARB, kg CH_4 or N_2O per MMBtu

0.001 = Factor to convert kg to metric tonnes

(4) The operator may elect to calculate CH_4 and N_2O emissions using ARB approved source specific emission factors derived from source tests conducted at least annually under the supervision of ARB or the local air pollution control district or air quality management district. Upon approval of a source test plan by ARB, the source test procedures in that plan shall be repeated in future years to update the source specific emission factors annually. In the absence of source specific emission factors approved by ARB, the operator shall use the default emission factors provided in Appendix A.

(c) **Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Heat Content.**

(1) The operator shall use the following equation to calculate fuel combustion CO_2 emissions by fuel type using the measured heat content of the fuel combusted:

$$CO_2 = \sum_{1}^{n} Fuel_P * HHV_P * EF * 0.001$$

Where:

CO_2 = combustion emissions from specific fuel type, metric tonnes CO_2 per year

n = Period/frequency of heat content measurements over the year (e.g. monthly n = 12)

$Fuel_P$ = Mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time

HHV_P = High heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume

EF = Default carbon dioxide emission factor supplied by ARB, kg CO_2 per MMBtu

0.001 = Factor to convert kg to metric tonnes

(A) The operator shall measure and record fuel consumption and the fuel's high heat value at frequencies specified by fuel type below. The operator may elect to utilize and record high heat values provided by the fuel supplier. The frequencies for measurements and recordings are as follows:

1. At receipt of each new fuel shipment or delivery or monthly for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, and LPG (ethane, propane, isobutene, n-Butane, unspecified LPG);

2. Monthly for natural gas with high heat value >975 and <1100 Btu per scf. Natural gas with high heat value <975 or >1100 Btu per scf shall use the methodology provided in 95125 (d);

3. Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.

(B) When measured by the operator or fuel supplier, high heat values shall be determined using the following methods:

1. For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (2006).

2. For middle distillates and oil, use ASTM D240-02 (2007) or ASTM D4809-00 (Reapproved 2005).

(d) ***Method for Calculating CO_2 emissions from Fuel Combustion Using Measured Carbon Content*** - For each type of fuel combusted at the facility, the operator shall calculate CO_2 emissions using the appropriate method below:

(1) ***Solid fuels.***

(A) Operators combusting solid fuels shall use the following equation to calculate CO_2 emissions:

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 3.664$$

Where:

CO_2 = carbon dioxide emissions, metric tonnes per year
$Fuel_n$ = mass of fuel combusted in month "n", metric tonnes per year
CC_n = carbon content from fuel analysis for month "n", percent (e.g. 95% expressed as 0.95)
3.664 = conversion factor for carbon to carbon dioxide

(B) The carbon content of all solid fuels shall be measured and recorded monthly. The monthly solid fuel sample shall be a composite sample of weekly samples. The solid fuel shall be sampled at a location after all fuel treatment operations (e.g. coal milling) and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion. Each weekly sub-sample shall be collected at the same time (day and hour) of the week and/or at a time when the fuel consumption rate is representative and unbiased. Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample. The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis. One in twelve composite samples shall be randomly selected for additional analysis of its discreet constituent samples. This information will be used to monitor the homogeneity of the composite.

(C) When measured by the operator or fuel supplier, carbon content shall be determined using the following ASTM method:

For coal and coke: ASTM 5373-02 (Re-approved 2007) which is incorporated by reference herein.

(2) ***Liquid fuels.***

(A) Operators combusting liquid fuels shall use the following equation to calculate CO_2 emissions:

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide emissions, metric tonnes per year
$Fuel_n$ = volume of fuel combusted in month "n", gallons per year
CC_n = carbon content from fuel analysis for month "n", kg C per gallon fuel
3.664 = conversion factor for carbon to carbon dioxide
0.001 = factor to convert kg to metric tonnes

(B) The carbon content shall be measured and recorded monthly. When measured by the operator or fuel supplier, carbon content shall be determined using the following ASTM methods: For petroleum-based liquid fuels, use ASTM D5291-02 "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants", ultimate analysis of oil or computations based on ASTM D3238-95 (Re-approved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Re-approved 2002), all incorporated by reference herein.

(3) ***Gaseous Fuels.*** Operators combusting gaseous fuels shall use the following equation to calculate CO_2 emissions:

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 1/MVC * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide emissions, metric tonnes per year
$Fuel_n$ = volume of gaseous fuel combusted in month "n", scf
CC_n = carbon content from fuel analysis for month "n", kg C per kg-mole fuel
MVC = molar volume conversion factor (849.5 scf/kg-mole)
3.664 = conversion factor for carbon to carbon dioxide
0.001 = Factor to convert kg to metric tonnes

(A) The carbon content shall be measured and recorded monthly. When measured by the operator or fuel supplier, carbon content shall be determined using the following ASTM method. ASTM D1945-03 or

ASTM D1946-90 (Re-approved 2006) which is incorporated by reference herein.

(e) ***Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Heat and Carbon Content.***

(1) The operator shall use the following method to calculate CO_2 emissions from fuel gas systems in the oil and gas sector, including combusted refinery fuel gas, still gas, process gas, associated gas or pressure swing adsorption off-gas using both high heat value (HHV) and fuel carbon content.

(2) Each fuel gas system that provides fuel to one or more combustion devices shall be subject to the measurement and reporting methods described herein. The operator shall obtain fuel samples and choose measurement locations in a manner that minimizes bias and is representative of each fuel gas system.

(3) For each separate fuel gas system, the operator shall calculate a daily fuel specific emission factor using the equation shown below.

$$EF_{CO2\text{-}A} = CC_A/HHV_A * MW_{CO2}/MVC * 0.001$$

Where:

$EF_{CO2\text{-}A}$ = daily CO_2 emission factor for fuel gas system A (tonnes CO_2/MMBtu)

CC_A = fuel gas carbon content for fuel gas system A (kg carbon/kg fuel)

HHV_A = high heating value for fuel gas system A (MMBtu/scf)

MW_{CO2} = molecular weight of CO_2

MVC = molar volume conversion (849.5 scf/ kg-mole)

0.001 = factor to convert kg to metric tonnes

(A) The operator shall determine carbon content once per day for each fuel gas system, by on-line instrumentation or by laboratory analysis of a representative gas sample drawn from the system, using the method specified in section 95125(d)(3)(C).

(B) The operator shall determine high heating value from the fuel sample obtained to conduct carbon analysis, or from a continuous in-line monitor. When HHV is derived from an in-line monitor, operators shall use either an hourly average HHV value coinciding with the hour in which the carbon content determination was made (in the case where an on-line analyzer was used), or the hour in which the sample was

collected for analysis. The operator shall use the method specified in section 95125(c)(1)(B).

(4) For each refinery fuel gas system the operator shall use the system specific daily fuel emission factor calculated using the equation in section 95125(e)(3) to calculate daily CO_2 emissions from all combustion devices where the fuel gas from that system was combusted, using the following equation.

$$CO_{2\text{-}A} = \sum_{1}^{365} HHV_A * FR_A * EF_{CO2\text{-}A}$$

Where:

$CO_{2\text{-}A}$ = CO_2 emissions resulting from the combustion of fuel gas from system A (metric tonnes/yr)
HHV_A = daily average high heating value for system A (Btu/scf)
FR_A = daily fuel consumption for fuel gas system A (scf/d)
$EF_{CO2\text{-}A}$ = daily CO_2 emission factor for fuel gas system A (tonnes $CO_2/10^6$ Btu)

(5) The operator shall calculate and report total CO_2 emissions resulting from the combustion of fuel gas as the sum of CO_2 combustion emissions from each fuel gas system in the following manner:

$$CO_2 = CO_{2\text{-}A} + CO_{2\text{-}B} + CO_{2\text{-}C} + ...CO_{2\text{-}X}$$

Where:

CO_2 = total CO_2 emissions from the combustion of fuel gas (metric tonnes/yr)
$CO_{2A,B,C}$ = CO_2 emissions from the combustion sources in fuel gas system A,B,C, etc. (metric tonnes/yr)
$CO_{2\text{-}X}$ = CO_2 emissions from the combustion of fuel gas system X, where X is the total number of fuel gas systems (metric tonnes/yr)

(f) ***Method for Calculatin g CO_2 Emissions from Fuel Combustion for Fuel Mixtures.***

(1) Where individual fuels are mixed prior to combustion, the operator shall choose one of the two methods below to calculate and report CO_2 emissions.

(A) Measure the flow rate of each fuel stream prior to mixing, apply the fuel specific sampling scheme specified for each fuel, calculate CO_2 emissions for each fuel in the mixture and sum to calculate total combustion emissions.

(B) Measure the flow rate of the fuel mixture and apply the methodology specified in section 95125(e).

(2) This provision does not apply in situations where equipment such as a hot oil heater or flare functions as an abatement device. This provision does not apply where a primary fuel supply is augmented with low Btu gas recovered from a controlled source such as a product or crude oil storage tank.

(g) ***Method for Calculating CO_2 Emissions from Fuel Combustion Using Continuous Emissions Monitoring Systems.***

(1) Operators that combust fossil fuels other than refinery fuel gas, and operate continuous emissions monitoring systems (CEMS) in response to federal, state, or air pollution control district/air quality management district (AQMD/APCD) regulations, including air district operating permit programs that meet the requirements of 40 CFR Part 60, may use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. The operator shall report CO_2 emissions for the report year in metric tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to metric tonnes.

(2) Operators that combust biomass or municipal solid waste and operate a CEMS in response to federal, state, or AQMD/APCD regulations including air district operating permit programs that meet the requirements of 40 CFR Part 60, may use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. The operator shall report CO_2 emissions for the report year in metric tonnes based on the sum of hourly CO_2 mass emissions over the year and converted to metric tonnes. Emissions shall not be based on O_2 concentrations.

(3) The operator of a facility that combusts municipal solid waste who chooses to calculate CO_2 emissions using the methodology provided in section 95125(g)(2) shall determine the portion of emissions associated with the combustion of biomass-derived fuels using the method provided in section 95125(h)(2).

(4) The operator who chooses to report CO_2 emissions using CEMS data and co-fires a fossil fuel with a biomass-derived fuel shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass-derived fuel using the method provided in section 95125(h)(2). The operator may elect to calculate CO_2 emissions for the fossil fuel using methods as designated in section 95111(c) by fuel type and then subtract

the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5) The operator who chooses to reports CO_2 emissions using CEMS data is relieved of requirements to separately report process emissions from combustion emissions or to report emissions separately for different fossil fuels when only fossil fuels are co-fired. In this circumstance operators shall still report fuel use by fuel type as otherwise required in this article.

(6) If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing continuous monitoring systems for the purpose of measuring CO_2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 as applicable to the facility.

(7) If a facility does not have a continuous emissions monitoring system and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CRF Part 75. The operator shall use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. The operator shall report CO_2 emissions for the report year in metric tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to metric tonnes.

(h) ***Method for Calculating CO_2 Emissions from Combustion of Biomass or Municipal Solid Waste.***

(1) The operator shall use the following method to calculate CO_2 emissions in the report year from combustion of biomass or municipal solid waste.

(A) CO_2 emissions from combusting biomass or municipal solid waste shall be calculated using the following equation:

$$CO_2 = Heat * CC_{EF} * 3.664 * 0.001$$

Where:
CO_2 = CO_2 emissions from fuel combustion, metric tonnes per year
Heat = Heat calculated in section 95125(h)(1)(B), MMBtu per year
CC_{EF} = Default carbon content emission factor provided in Appendix A, kg carbon per MMBtu
3.664 = CO_2 to carbon molar ratio
0.001 = Conversion factor to convert kilograms to metric tonnes

(B) Heat content shall be calculated using the following equation:

Heat = Steam * B

Where
Heat = Heat, MMBtu per year
Steam = Actual Steam generated, pounds per year
B = Boiler Design Heat Input/Boiler Design Steam Output, as Design MMBtu per pound Steam

(2) The operator shall determine the biomass-derived portion of CO_2 emissions from combusting municipal solid waste using ASTM D6866-06a. The operator shall conduct ASTM D6866-06a analysis at least every three months, and each gas sample analyzed shall be taken during normal operating conditions over at least 24 consecutive hours or for as long as necessary to gather a sample large enough to meet the specifications of ASTM D6866-06a. The operator shall divide total CO_2 emissions between biomass-derived emissions and non-biomass-derived emissions using the average proportionalities of the samples analyzed. If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

(3) Operators of facilities that combust biomass-derived fuels or municipal solid waste may elect to calculate CO_2 emissions using ARB approved source specific emission factors derived from source tests conducted at least annually under the supervision of ARB or the local air pollution control district or air quality management district. Upon approval of a source test plan by ARB, the source test procedures in that plan shall be repeated in future years to update the source specific emission factors annually. In the absence of source specific emission factors approved by ARB, the operator shall use the default emission factors provided by ARB.

(i) ***Method for Calculating Mobile Combustion Emissions.***

(1) The operator shall use the following equation to compute mobile combustion CO_2 emissions for the report year by fuel type:

$$CO_2 = Fuel * EF_{CO2} * 0.001$$

Where:
CO_2 = emissions from mobile combustion by fuel type, metric tonnes
Fuel = volume of fuel consumed, gallons
EF_{CO2} = default emission factor by fuel type supplied by ARB, kg CO_2/gallon
0.001 = conversion factor to convert kg to metric tonnes

(2) The operator shall obtain volume of fuel consumed during the report year from fuel records data (including bulk fuel purchase records, collected fuel receipts, official logs of vehicle fuel gauges or storage tanks) as shown in section 95125(i)(1)(A). The operator may elect to calculate fuel use from miles traveled per vehicle using the fuel economy method shown in section 95125(i)(1)(B).

(A) The operator shall use the following equation to calculate mobile source fuel consumption from fuel records data:

$$Fuel = FP + FS_{beg} - FS_{end}$$

Where:
Fuel = volume of fuel consumed, gallons
FP = total fuel purchases, gallons
FS_{beg} = amount of fuel stored at the beginning of the year, gallons
FS_{end} = amount of fuel stored at the end of the year, gallons

(B) The operator shall use the following equation to calculate mobile source fuel consumption using U.S. EPA fuel economy values for specific vehicle models and miles traveled per vehicle:

$$Fuel = \sum_{i}^{n} Mileage_i / (FE_{city,i} * DP_{city,i} + FE_{highway,i} * DP_{highway,i})$$

Where:
Fuel = volume of fuel consumed, gallons
$Mileage_i$ = total miles traveled by vehicle i, miles
$FE_{city,i}$ = U.S. EPA specified vehicle i fuel economy for city driving, miles per gallon
$DP_{city,i}$ = proportion of miles traveled spent in city driving conditions for vehicle i, percent/100 (0.55 may be used as a default value or a fleet specific number may be substituted if known)
$FE_{highway,i}$ = U.S. EPA specified vehicle i fuel economy for highway driving, miles per gallon
$DP_{highway,i}$ = proportion of miles traveled spent in highway driving conditions for vehicle i, percent/100 (0.45 may be used as a default value or a fleet specific number may be substituted if known)
n = total number of vehicles

(3) The operator shall use the following equation to compute mobile combustion CH_4 and N_2O emissions by vehicle type:

$$TE = EF * Mileage * 0.000001$$

Where:

TE = total emissions of CH_4 or N_2O from mobile combustion by vehicle type, metric tonnes per year

EF = emission factor by vehicle type and fuel type provided by ARB, g of CH_4 or N_2O/mile

Mileage = total miles traveled by vehicle type, miles per year

0.000001 = conversion factor to convert grams to metric tonnes

(A) If mile traveled data are not available, the operator may elect to back calculate total miles traveled by vehicle type from fuel usage data using U.S. EPA fuel economy values for specific vehicle models and the following equation:

$$\text{Mileage} = \sum_{i}^{n} \text{Fuel}_i * (FE_{city,i} * DP_{city,i} + FE_{highway,i} * DP_{highway,i})$$

Where:

Mileage = total miles traveled by vehicle type, miles

Fuel_i = volume of fuel consumed by vehicle model i, gallons

$FE_{city,i}$ = U.S. EPA specified vehicle i fuel economy for city driving, miles per gallon

$DP_{city,i}$ = proportion of miles traveled spent in city driving for vehicle i, percent/100 (0.55 may be used as a default value or a fleet specific number may substituted if known)

$FE_{highway,i}$ = U.S. EPA specified vehicle i fuel economy for highway driving, miles per gallon

$DP_{highway,i}$ = proportion of miles traveled spent in highway driving conditions for vehicle i, percent/100 (0.45 may be used as a default value or a fleet specific number may be substituted if known)

n = number of vehicles

(j) ***Method for Calculating Fugitive CH_4 Emissions from Coal Storage.***

The operator shall calculate fugitive CH_4 emissions from coal storage using the following equation:

$$CH_4 = PC * EF * CF_1 / CF_2$$

Where

CH_4 = CH_4 emissions in the report year, metric tonnes

PC = Purchased coal, tons

EF = Default emission factor for CH_4 based on coal origin and mine type provided in Appendix A, scf CH_4/ton

CF_1 = Conversion factor equals 0.04228, lbs CH_4/scf
CF_2 = Conversion factor equals 2,204.6, lbs/metric ton

(k) ***Method for Calculating Indirect Electricity Usage.***

The operator who consumes electricity that is purchased or acquired from a retail provider or a facility they do not own or operate shall report electricity use and identify the provider(s) for all electricity consumed at the facility.

(1) For each electricity provider, the operator shall sum electricity use (kWh) from billing records for the report year. If the records do not begin or end exactly on January 1 and December 31, but span two calendar years, the facility shall pro-rate its power usage according to the fraction of days billed for each month in each year using the equation shown.

Calculating electricity use for partial months:

Partial Month Electricity use (kWh) =
*(electricity use (kWh) in period billed / total number days in period billed) * (number of days billed in partial month)*

(2) The operator shall report by electricity provider the electricity consumed at the facility in kilowatt-hours (kWh)..

(l) ***Method for Calculating Indirect Thermal Energy Usage.***

The operator who consumes steam, heat, and/or cooling that is purchased or acquired from a facility that they do not own or operate shall report thermal energy use and identify the provider(s) for all thermal energy consumed at the facility. .

(1) For each thermal energy provider, the operator shall obtain data from the facility's thermal use records, and sum this usage for the report year. If the records do not begin or end exactly on January 1 and December 31, but span two calendar years, the facility shall pro-rate its indirect thermal energy usage according to the fraction of days billed for each month in each year using the equation shown.

Calculating thermal use for partial months:

Partial Month Thermal use (Btu) =
*(thermal use (Btu) in period billed / total number days in period billed) * (number of days billed in partial month)*

(2) The operator shall report by thermal energy provider the thermal energy consumed at the facility in British thermal units (Btu).

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

Subarticle 4. Requirements for Verification of Greenhouse Gas Emissions Data Reports and Requirements Applicable to Emissions Data Verifiers

95130. Requirements for Verification of Emissions Data Reports. Operators shall obtain the services of an accredited verification body for purposes of verifying emissions data reports submitted under this article, as specified in section 95103(c).

(a) ***Annual Verification.***

(1) Operators required to obtain annual verification under section 95103(c) shall be subject to full verification requirements beginning in the calendar year following their first report year. Upon completion of a positive verification opinion under full verification requirements, the operator may choose to obtain two years of less intensive verification services. This cycle may be repeated in subsequent three-year cycles, but full verification requirements shall not apply less frequently than every three years.

(2) Operators subject to annual verification shall not use the same verification body for a period of more than six consecutive years. The operator may resume verification services with a verification body that has provided verification services for six consecutive years after at least three years of not contracting for such services with the same verification body.

(b) ***Triennial Verification.***

(1) Operators required to obtain triennial verification under section 95103(c) shall be subject to full verification requirements every year that verification is required. However, such operators may choose to obtain less intensive verification services for the two years following completion of full verification services and prior to the next three-year cycle.

(2) Operators subject to triennial verification requirements shall not use the same verification body for more than two consecutive verification cycles. The operator may resume verification services with that verification body after one verification cycle of not obtaining verification services from the same verification body.

(c) Operators who are members of the California Climate Action Registry may use the same verification body for ARB and Registry emissions data reports, when that body has met both ARB and Registry accreditation requirements. When an operator is required to rotate verification bodies by the California Climate Action Registry, the operator shall also rotate the verification body used to meet the verification requirements of this article if the operator chooses to use the same verification body.

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95131. Requirements for Verification Services. Verification services shall be subject to the following requirements.

(a) ***Notice of Verification Services.*** After the Executive Officer has provided a determination that the potential for a conflict of interest is acceptable as specified in section 95133(f) and that verification services may proceed, the verification body shall submit a notice of verification services to ARB. The verification body may begin verification services for the operator ten working days after the notice is received by the Executive Officer, or earlier if approved by the Executive Officer in writing. The notice shall include the following information:

(1) A list of the staff who will be designated to provide verification services as a verification team, including the names of each designated staff member, the lead verifier, and all subcontractors, and a description of the roles and responsibilities each member will have during verification;

(2) Documentation that the verification team has the skills required to provide verification services for the reporting facility. This shall include a demonstration that a verification team includes at least one member accredited to provide sector specific verification services when required below:

(A) For providing verification services to a retail provider or marketer, at least one verification team member must be accredited by ARB as an electricity transactions specialist.
(B) For providing verification services to the operator of a petroleum refinery or hydrogen plant, at least one verification team member must be accredited by ARB as a refinery specialist.
(C) For providing verification services to the operator of a cement plant, at least one verification team member must be accredited by ARB as a cement plant specialist.

(3) General information on the lead verifier and the operator, including:

(A) The name, office address, telephone number, and e-mail address of the lead verifier;
(B) The name of the operator and the facilities and other locations that will be subject to verification services; operator contact, address, telephone number, and e-mail address;
(C) The industry sector, and the Standard Industrial Classification and North American Industry Classification System (NAICS) codes of the reporting facility;

(D) The expected date(s) of on-site visits, with facility address and contact information;
(E) A brief description of expected verification services to be performed, including expected completion date.

(b) Verification services shall include, but are not limited to, the following:

(1) ***Verification Plan.*** The verification team shall obtain information from the operator necessary to develop a verification plan. Such information shall include but is not limited to:

(A) Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, and electricity transactions as applicable;
(B) Information regarding the training or qualifications of personnel involved in developing the emissions data report;
(C) Description of the specific methodologies used to quantify and report greenhouse gas emissions, electricity transactions, and other required data as applicable;
(D) Information about the data management system used to track greenhouse gas emissions, electricity transactions, and other required data as applicable.

(2) The verification team shall develop a verification plan that includes, at a minimum:

(A) Dates of proposed meetings and interviews with reporting facility personnel;
(B) Dates of proposed site visits;
(C) Types of proposed document and data reviews;
(D) Expected date for completing verification services.

(3) The verification team shall discuss with the operator the scope of the verification services and request any information and documents needed for initial verification services. The verification team shall review the documents submitted and plan a review of original documents and supporting data for the emissions data report.

(4) ***Site visits.*** The verification team shall at a minimum make one site visit, in the first year of each three-year reporting cycle, to each facility for which an emissions data report is submitted. The verification team shall visit the headquarters or other location of central data management when the operator is also a retail provider or marketer, The objectives of the verification team during the site visit shall include the following:

(A) The verification team shall ensure that all sources specified in sections 95110 to 95115 as applicable to the operator are accounted for appropriately;
(B) The verification team shall review and understand the data management systems used by the operator to track, quantify, and report greenhouse gas emissions and, when applicable, electricity transactions. The verification team shall evaluate the uncertainty and effectiveness of these systems.
(C) The verification team shall collect and review other information that, in the professional judgment of the team, is needed in the verification process.

(5) The verification team shall review facility operations to identify applicable greenhouse gas emissions sources. This shall include a review of the emissions inventory and each type of emission source to assure that all sources applicable under 95110 to 95115 of this article are properly included in the inventory.

(6) Operators shall make available to the verification team all information and documentation used to calculate and report emissions, electricity transactions, and other information required under this article, as applicable.

(7) As applicable for retail providers and marketers, the verification team shall review electricity transaction records, including receipts of power attributed to the Northwest or Southwest region as verifiable via North American Electric Reliability Corporation (NERC) E-Tags.

(8) ***Sampling Plan.*** As part of confirming emissions data or electricity transactions the verification team shall develop a sampling plan that meets the following requirements:

(A) The verification team shall develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale and complexity of the verification services for an operator. The analysis shall review all inputs for the development of the submitted emissions data report, the rigor and appropriateness of the greenhouse gas or electricity transaction data management system, and the coordination within a facility or retail provider's or marketer's organization to manage the operation and maintenance of equipment or systems used to develop emissions data reports.

(B) The verification team shall include in the sampling plan a ranking of emissions sources by amount of contribution to total CO_2 equivalent emissions for the operator, and a ranking of emissions sources with largest estimation uncertainty. As applicable and deemed appropriate

by the verifier, electricity transactions shall also be ranked or evaluated for relative amount of power exchanged and any uncertainties that may apply to data summaries provided by the retail provider or marketer.

(C) The verification team shall include in the sampling plan a qualitative narrative of uncertainty risk assessment in the following areas as applicable under sections 95110 to 95115:

1. data acquisition equipment;
2. data sampling and frequency;
3. data processing and tracking;
4. emissions calculations;
5. data reporting;
6. management policies or practices in developing emissions data reports.

(D) The verification team may change the sampling plan as relevant information becomes available and potential issues of misstatement or nonconformance with regulation requirements emerge.

(9) ***Data checks.*** To determine the reliability of the submitted emissions data report, the verification team shall use data checks. Such data checks shall focus first on the largest and most uncertain estimates of emissions and electricity transactions, and shall include the following:

(A) The verification team shall use data checks to ensure that the appropriate methodologies and emission factors have been applied for the emissions sources and electricity transactions required under sections 95110 to 95115;

(B) The verification team shall choose emissions sources and, as applicable, electricity transactions, for data checks based on their relative sizes and risks of uncertainty as indicated in the sampling plan;

(C) The verification team shall use professional judgment in the number of data checks required for the team to conclude with reasonable assurance that the reported emissions and transactions are free or not free of material misstatement and nonconformance.

(10) ***Emissions data report modifications.*** If as a result of review by the verification team and prior to completion of a verification opinion the operator chooses to make improvements or corrections to the submitted emissions data report, a revised emissions data report may be submitted to ARB as specified by section 95104(d). The operator shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the operator for five years.

(11) ***Findings.*** To verify that the emissions data report is free of material misstatement, the verification team shall make its own determination of total emissions for checked sources and shall determine whether there is reasonable assurance that the reported emissions are within 95% of the CO_2e total actual emissions. To assess conformance the team shall review the methods and factors used to develop the emissions data report for adherence to the requirement of this article.

(A) The verification team shall keep a log of any issues identified that may impact material misstatement and nonconformance determinations and how those issues were resolved.

(c) Completion of verification services shall include:

(1) ***Verification opinion.*** At the completion of verification services the verification body shall complete a verification opinion. Before that opinion is made available to the operator, the verification body shall have the verification services and findings of the verification team independently reviewed within the verification body by a lead verifier not involved in services for that operator during that year.

(2) When the verification team completes its findings:

(A) The verification body shall provide to the operator a detailed verification report. The verification report shall at minimum include the verification plan, sampling plan, the detailed comparison of the data checks with the submitted emissions data report, the issues log, and any qualifying comments on findings during verification services. The detailed verification report shall be made available to ARB upon request.

(B) The lead verifier shall provide a verification opinion to the ARB attesting that the verification body has found the submitted emissions data report free of material misstatement and nonconformance or, alternatively, the emissions data report does not meet the material misstatement or conformance requirements as specified in this article. In the verification opinion, the lead verifier in the verification team shall attest that the verification team has carried out all verification services as required by this article, and the lead verifier that has conducted the independent review of verification services and findings specified in section 95131(c)(1) shall attest to his or her independent review on behalf of the verification body.

(3) If the verification body provides an adverse verification opinion to the ARB on the emissions data report, the operator may modify the report to remove any material misstatement or nonconformance found by the verification

team in order to receive a subsequent positive verification opinion. The modified report must be submitted to ARB before the applicable verification deadline, unless the operator makes a request to the Executive Officer as provided below in section 95131(c)(3)(A).

(A) If the operator and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification opinion, the operator may petition the ARB Executive Officer to make a final decision as to the verifiability of the submitted emissions data report.

(B) If the Executive Officer determines that the emissions data report does not meet the standards specified in this article, the operator shall submit for re-verification within thirty days of the date of this decision a revised emissions data report that reflects the Executive Officer's determination. In re-verifying any revised emissions data reports, the verification team shall be subject to the requirements in section 95131(c)(1)-(2)..

(d) Upon request by the Executive Officer the operator shall provide the data used to generate an emissions data report, including all data available to a verifier in the conduct of verification services. ARB may also review the full verification report given by the verification body to the operator. The full verification report shall be provided to the Executive Officer upon request.

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95132. Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers.

(a) The accreditation requirements specified in this subarticle shall apply to all verification bodies, lead verifiers, and verifiers that wish to provide verification services under this article.

(b) The Executive Officer may issue accreditation to verification bodies, lead verifiers, and verifiers that meet the requirements specified in this section.

(1) ***Verification Body Accreditation Application.*** To apply for accreditation as a verification body, the applicant shall submit the following information to the Executive Officer, except as provided in section 95132(b)(1)(F).

(A) A list of all verification staff and a description of their duties and qualifications, including ARB accredited verifiers on staff. The applicant

shall demonstrate staff qualifications by listing each individual's education, experience, professional licenses, and other pertinent information.

1. A verification body shall have at least two verifiers that have been accredited as lead verifiers, as specified in section 95132(b)(2);
2. A verification body shall have at least five total full-time staff.

(B) The applicant shall provide a list of any judicial proceedings filed against the body within the previous 5 years, with an explanation as to the nature of the proceedings.

(C) The applicant shall provide documentation to demonstrate that the proposed verification body has a minimum of one million U.S. dollars of professional liability insurance.

(D) The applicant shall provide a demonstration that the body has policies and mechanisms in place to prevent conflicts of interest and to identify and resolve potential conflict of interest situations if they arise. The applicant shall provide the following information:

1. Identification of services provided by the verification body, the industries and customers that the body serves, and the locations where those services are provided;
2. An organization chart that includes the verification body and any related entities, a brief description of services provided by related entities, the industries and customers served, and locations where those services are provided.

(E) The applicant shall provide a demonstration that the body has procedures or policies to support staff technical training as it relates to verification.

(F) If the applicant is a California air pollution control district or air quality management district, the requirements of section 95132(b)(1)(a)(2) and 95132(b)(1)(B)-(D) do not apply, except that the applicant shall provide a demonstration that the district has policies and mechanisms in place to prevent conflicts of interest and resolve potential conflict of interest situations if they arise.

(2) ***Lead Verifier Accreditation Application.*** To apply for accreditation as a lead verifier, the applicant shall submit the following documentation to the Executive Officer.

(A) Evidence that the applicant has acted as project manager or lead capacity in one or more of the following greenhouse gas reporting programs:

1. As a registered lead verifier in good standing for the California Climate Action Registry prior to December 1, 2007, having performed at least three verifications by December 31, 2007; or,
2. As a registered lead verifier in good standing for the United Kingdom Accreditation System, having performed at least three verifications by December 31, 2007; or,
3. Is accredited by a recognized agency in ISO 14065, 14064 or ISO 19011, having performed at least three verifications by December 31, 2007.

(B) Evidence that the applicant has been an ARB accredited verifier for two continuous years and has worked as a verifier in at least three completed verifications under the supervision of an ARB accredited lead verifier, with evidence of favorable assessment for services performed; or,

(C) Evidence that the applicant has worked as a project manager or leadperson for not less than four years, of which two may be graduate level work:
1. In the development of GHG or other air emissions inventories: or,
2. As a lead environmental data auditor in the private sector.

(D) Evidence that the applicant has completed ARB approved general verification training and received a passing score on an exit examination.

(E) For each applicant for accreditation as a lead verifier who has not submitted evidence of qualification under sections 95132(b)(2)(A), 95132(b)(2)(B), or 95132(b)(2)(C)2, evidence that the applicant has completed ARB approved auditor training and received a passing score on an exit examination.

(3) ***Verifier Accreditation Application.*** To apply for accreditation as a verifier, the applicant shall submit the following documentation to the Executive Officer:

(A) The applicant must submit evidence demonstrating the minimum educational background required to act as a verifier for ARB. "Minimum education background" means that the applicant has either:
1. A bachelors level college degree in science, technology, business, statistics, mathematics, environmental policy, economics, or financial auditing; or
2. Evidence demonstrating the completion of significant and relevant work experience or other personal development activities that have provided the applicant with the communication, technical and analytical skills necessary to conduct verification.

(B) The applicant must also submit evidence demonstrating sufficient workplace experience to act as a verifier, including evidence that the applicant has a minimum of two years of fulltime work experience in a professional role involved in emissions data management, emissions technology, or other technical skills necessary to conduct verification.

(4) All verifier applicants shall take an ARB approved general verification training course and receive a passing score on an exit examination.

(5) ***Sector Specific Verifiers.*** All applicants seeking to be approved as sector specific verifiers as specified in section 95131(a)(2) must, in addition to meeting the requirements for verifier qualification, take ARB sector specific verification training and receive a passing score on an exit examination.

(6) Nothing in this section shall be construed as preventing the Executive Officer from requesting additional information or documentation from an applicant after receipt of the application for accreditation as a verification body, lead verifier, or verifier; or from seeking additional information from other persons or entities regarding the applicant's fitness for qualification.

(c) ***ARB Accreditation.***

(1) Within 90 days of receiving an application for accreditation as a verification body, lead verifier, or verifier, the Executive Officer shall inform the applicant in writing either that the application is complete or that additional specific information is necessary required to make the application complete.
(2) Upon a finding by the Executive Officer that an application for accreditation as a verifier or lead verifier is complete, the prescreening requirement is met and the applicant may attend the verification training required by this section.
(3) Within 45 days following completion of the application process and all applicable training and examination requirements, the Executive Officer shall act to grant or withhold accreditation for the verification body, lead verifier, or verifier.
(4) The Executive Officer shall issue an Executive Order to grant accreditation to the applicant if the evidence of qualification submitted by the applicant has been found complete and sufficient and the applicant has successfully completed the required training and examination(s).
(5) The Executive Order for accreditation is valid for a period of three years, whereupon the applicant may re-apply for accreditation as a verifier, lead verifier, or verification body. All ARB approved general or sector specific verification training and examination requirements applicable at the time of re-application must be met for accreditation to be renewed by the Executive Officer.

(6) The Executive Officer shall issue an Executive Order to grant accreditation to a verification body if evidence of qualification submitted by the applicant has been found to meet the requirements of section 95132(b)(1).
(7) The Executive Officer and the applicant may mutually agree to longer time periods than those specified in this subsection (c), and the applicant may submit additional supporting documentation before a decision has been made by the Executive Officer.

(d) ***Modification or Revocation of an Executive Order Approving a Third Party Verifier.*** The Executive Officer may review and, for good cause, modify or revoke an Executive Order providing accreditation to a verification body, lead verifier, or verifier. The Executive Officer shall not modify or revoke an Executive Order without affording the verification body, lead verifier, or verifier the opportunity for a hearing in accordance with the procedures specified in title 17, California Code of Regulations, section 60055.1 et seq.

(e) ***Subcontracting.*** The following requirements shall apply to any verification body that elects to subcontract verification services.

(1) All subcontractors must be accredited by ARB to perform the verification services for which the subcontractor has been engaged by the verification body.
(2) The verification body must assume full responsibility for verification services performed by subcontractor verifiers or verification bodies.
(3) A verification body shall not use subcontractors to meet the minimum staff total or lead verifier requirements specified section 95132(b)(1)(A)1. and section 95132(b)(1)(A)2.
(4) A verification body or verifier acting as a subcontractor to another verification body shall not further subcontract or outsource verification services for an operator.
(5) A verification body that engages a subcontractor shall be responsible for demonstrating an acceptable level of conflict of interest, as provided in section 95133, between its subcontractor and the operator for which it will provide verification services.

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

95133. Conflict of Interest Requirements for Verifiers.

(a) The conflict of interest provisions of this section shall apply to verification bodies and verifiers accredited by ARB to perform verification services.

(b) The potential for a conflict of interest shall be deemed to be high where:

(1) The verification body and operator share any management or board of directors membership, or any of the management staff of the operator have been previously employed by the verification body, or vice versa, within the previous three years, or

(2) Within the previous three years, any staff member of the verification body or any related entity has provided to the any of the following non-verification services:
   (A) Designing, developing, implementing, or maintaining an inventory or information or data management system for facility greenhouse gases, or, where applicable, electricity transactions;
   (B) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis;
   (C) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;
   (D) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting facility;
   (E) Appraisal services of carbon or greenhouse gas liabilities or assets;
   (F) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;
   (G) Managing any health, environment or safety functions;
   (H) Bookkeeping or other services related to the accounting records or financial statements;
   (I) Any service related to information systems, unless those systems will not be part of the verification process;
   (J) Appraisal and valuation services, both tangible and intangible,
   (K) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services shall not be part of the verification process;
   (L) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;
   (M) Any internal audit service that has been outsourced by the operator that relates to the operator's internal accounting controls, financial systems or financial statements, unless the result of those services shall not be part of the verification process;
   (N) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the operator;
   (O) Any legal services;
   (P) Expert services to the operator or their legal representative for the purpose of advocating the operator's interests in litigation or in a regulatory or administrative proceeding or investigation, unless providing factual testimony.

(3) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body has provided verification services

for the operator within the last three years, except within the time periods in which the operator is allowed to use the same verification body as provided by sections 95130(a) and 95130(b).

(c) The potential for a conflict of interest shall be deemed to be low where no potential for a conflict of interest is found under section 95133(b) and any non-verification services provided by any member of the verification body to the operator within the last three years are valued at less than 20 percent of the fee for the proposed verification.

(d) The potential for a conflict of interest shall be deemed to be medium where the potential for a conflict of interest is not deemed to be either high or low as specified in sections 95132(b) and 95132(c).

(1) If a verification body identifies a medium potential for conflict of interest and wishes to provide verification services for the operator, the verification body shall submit, in addition to the submittal requirements specified in section 95133(e), a plan to avoid, neutralize, or mitigate the potential conflict of interest situation. At a minimum, the conflict of interest mitigation plan shall include:

(A) A demonstration that any conflicted individuals have been removed and insulated from the project.
(B) An explanation of any changes to the organizational structure or verification body to remove the conflict of interest. A demonstration that any conflicted unit has been divested or moved into an independent entity or any conflicted subcontractor has been removed.
(C) Any other circumstance that specifically addresses other sources for potential conflict of interest.

(2) The Executive Officer shall evaluate the conflict of interest mitigation plan as provided in section 95133(f) and determine whether verification services may proceed.

(e) ***Conflict of Interest Submittal Requirements for Accredited Verifiers.***

(1) Before the start of any work related to providing verification services to an operator, a verification body must first be authorized by the Executive Officer in writing to provide verification services. To obtain authorization the verification body shall submit to the Executive Officer a self-evaluation of the potential for any conflict of interest that the body, its partners, or any subcontractors performing verification services may have with the operator for which it will perform verification services. The submittal shall include the following:

(A) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in sections 95133(b), (c), and (d);

(B) An organizational chart of the verification body and brief description of the verification body and any related entities;

(C) Identification of whether any member of the verification team has previously provided verification services for the reporting facility and, if so, the years in which such verification services were provided;

(D) Identification of whether any member of the verification team or related entity has engaged in any non-verification services of any nature with the reporting facility either within or outside California during the previous three years. If non-verification services have previously been provided, the following information shall also be submitted:

1. Identification of the nature and location of the work performed for the operator and whether the work is similar to the type of work to be performed during verification, such as emissions inventory, auditing, energy efficiency, renewable energy, or other work with implications for the operator's greenhouse gas emissions or the accounting of greenhouse gas emissions or electricity transactions.

2. The nature of past, present or future relationships with the reporting facility, retail provider, or marketer including:
   a. Instances when any member of the verification team has performed or intends to perform work for the operator;
   b. Identification of whether work is currently being performed for the operator, and if so, the nature of the work;
   c. How much work was performed for the operator in the last three years, in dollars or percentage of verifier's revenues or gross income;
   d. Whether any member of the verification team has any contracts or other arrangements to perform work for the operator or a related entity;
   e. How much work related to greenhouse gases or electricity transactions the verification team has performed for the reporting facility or related entities in the last three years, in dollars or percentage of the body's and its subcontractors' revenues or gross income.

3. Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

(E) A list of names of the staff that would perform verification services for the operator, and a description of any instances of personal or family

relationships with management or employees of the operator that potentially represent a conflict of interest; and,

(2) Identification of any other circumstances known to the verification body or operator that could result in a conflict of interest.

(f) ***Conflict of Interest Determinations.*** The Executive Officer shall review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform verification services for the operator.

(1) The Executive Officer shall notify the verification body in writing when the conflict of interest evaluation information submitted under section 95132(e) is deemed complete. Within forty-five days of deeming the evaluation information complete, the Executive Officer shall determine whether the verification body is authorized to proceed with verification and shall so notify the verification body.

(2) If the Executive Officer determines the verification body or any member of the verification team meets the criteria specified in section 95133(b), the Executive Officer shall find a high potential conflict of interest and verification services may not proceed.

(3) If the Executive Officer determines that there is a low potential conflict of interest, verification services may proceed.

(4) If the Executive Officer determines that the verification body and verification team have a medium potential for a conflict of interest, the Executive Officer shall evaluate the conflict of interest mitigation plan submitted pursuant to sections 95133(d), and may request additional information from the applicant to complete the determination. In determining whether verification services may proceed, the Executive Officer may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body and its subcontractors with the operator, and the cost of the verification services to be performed. If the Executive Officer determines that these factors when considered in combination demonstrate a low conflict of interest, then verification services may proceed.

(g) ***Monitoring Conflict of Interest Situations.***

(1) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to the Executive Officer regarding any potential for a conflict of interest situation that arises.. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(2) The verification body shall monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 days of entering into any contract with the operator for which the body has provided verification services, the verifier shall notify the Executive Officer of the contract and the nature of the work to be performed.

(3) The verification body shall report to the Executive Officer any changes in its organizational structure, including mergers, acquisitions, or divestitures, for one year after completion of verification services.

(4) The Executive Officer may invalidate a verification finding if a conflict of interest has arisen for any member of the verification team. In such a case, the operator shall be provided 180 days to complete re-verification.

(5) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this article, the Executive Officer may rescind accreditation of the body, its verifier staff, or its subcontractor(s) for any appropriate period of time as provided in section 95132(d).

NOTE: Authority cited: Sections 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

APPENDIX A

to the Regulation for the Mandatory Reporting
of Greenhouse Gase Emissions

ARB COMPENDIUM OF EMISSION FACTORS AND METHODS TO SUPPORT MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

October 19, 2007

ARB COMPENDIUM OF EMISSION FACTORS AND METHODS TO SUPPORT MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

October 2007

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1. Introduction

The contents of this compendium specify acceptable methods and emission factors that operators must use when preparing greenhouse gas emissions data reports for submission to the California Air Resources Board (ARB), as specified in the ARB Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

2. Unit Conversions

Table 1. Conversion Table		
To Convert From	**To**	**Multiply By**
Grams (g)	Tonnes (metric)	1×10^{-6}
Kilograms (kg)	Tonnes (metric)	1×10^{-3}
Megagrams	Tonnes (metric)	1
Gigagrams	Tonnes (metric)	1×10^{3}
Pounds (lbs)	Tonnes (metric)	4.5359×10^{-4}
Tons (long)	Tonnes (metric)	1.016
Tons (short)	Tonnes (metric)	0.9072
Barrels	Cubic metres (m^3)	0.15898
Cubic feet (ft^3)	Cubic metres (m^3)	0.028317
Litres	Cubic meters (m^3)	1×10^{-3}
Cubic yards	Cubic meters (m^3)	0.76455
Gallons (liquid, US)	Cubic meters (m^3)	3.7854×10^{-3}
Imperial gallon	Cubic meters (m^3)	4.54626×10^{-3}
Joule	Gigajoules (GJ)	1×10^{-9}
Kilojoule	Gigajoules (GJ)	1×10^{-6}
Megajoule	Gigajoules (GJ)	1×10^{-3}
Terajoule (TJ)	Gigajoules (GJ)	1×10^{3}
Btu	Gigajoules (GJ)	1.05506×10^{-6}
Kilocalorie	Gigajoules (GJ)	4.187×10^{-6}
Tonne oil eq. (toe)	Gigajoules (GJ)	41.86
kWh	Gigajoules (GJ)	3.6×10^{-3}
Btu / ft^3	GJ / m^3	3.72589×10^{-5}
Btu / lb	GJ / Tonnes (metric)	2.326×10^{-3}
Lb / ft^3	Tonnes (metric) / m^3	1.60185×10^{-2}
Psi	Bar	0.0689476
Kgf / cm^3 (tech atm)	Bar	0.980665
Atm	Bar	1.01325
Mile	Kilometer	1.6093
Hectares	Acres	2.471
Barrels	Gallons (liquid, US)	42

3. Global Warming Potentials

According to the Intergovernmental Panel on Climate Change (IPCC), the global warming potential (GWP) of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas. The reference gas used is CO_2. The values given below are those reported in the IPCC Second Assessment Report (IPCC 1996). These values are used to be consistent with other statewide and national Greenhouse Gas (GHG) inventories. Operators must use these values when converting emissions of greenhouse gases to carbon dioxide equivalent values (CO_2e) for purposes of estimating *de minimis* emissions as specified in section 95103(a)(6).

Table 2. Global Warming Potentials (100-Year Time Horizon)

Gas	GWP
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900

* The CH_4 GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.

Source: IPCC Climate Change 1995: The Science of Climate Change. (1996) Intergovernmental Panel on Climate Change, J.T. Houghton, L.G. Meira Filho, B.A. Callander, N. Harris, A. Kattenberg, and K. Maskell, eds. Cambridge University Press. Cambridge, U.K.

4. Method for Fuel Use to Carbon Dioxide Emissions Estimations

The following table shows the approximate amount of fuel that, when fully combusted, would result in 25,000 and 2,500 metric tonnes of CO_2 for selected common fuel types.

The 25,000 metric tonne threshold is the level at or above which general stationary sources of combustion are required to report under the regulation. Similarly, the 2,500 metric tonne threshold is the level at or above which electrical generating facilities ≥1MW are required to report. This information is provided to give operators a rough estimate of whether or not a given facility falls within the scope of ARB's mandatory reporting program. However, this table alone may not be used to demonstrate that that a facility has no reporting obligation.

These tables are based on the ARB accepted emission factors which are set forth in this document. If an operator is combusting multiple fuels types, or is using a fuel type not listed in this table, then the operator must multiply the amount of fuel consumed annually for each fuel type by the ARB provided emission factor and sum the emissions to determine annual CO_2 emissions from stationary combustion.

Table 3. Fuel Amounts Resulting in 25,000 or 2,500 MT of CO_2 by Fuel Type

Fuel Type	Fuel Units	Kg CO_2/Unit	Amount of fuel to produce 25,000 MT CO_2	Amount of fuel to produce 2,500 MT CO_2
Natural Gas (unspecified)	scf	0.05	459,140,464	45,914,046
LPG (energy use)	Gal	5.79	4,317,757	431,776
Distillate Fuel (#1,2 &4)	Gal	10.14	2,466,011	246,601
Motor Gasoline	Gal	8.80	2,841,174	284,117
Landfill Gas	MMBtu	52.03	480,503	48,050
Coal (Unspecified Other Industrial)	Short Ton	2,082.89	12,003	1,200
Jet Fuel	Gal	9.56	2,614,682	261,468
Kerosene	Gal	9.75	2,562,972	256,297
Petroleum Coke	MMBtu	102.04	244,996	24,500
Crude Oil	Gal	10.29	2,430,348	243,035

5. Emission Factors

When working with the following emission factor tables the molar mass ratio of carbon dioxide to carbon (CO_2/C) is assumed to be 3.664. Complete oxidation is assumed for all fuels (oxidation factor = 1).

(a) Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors for Stationary Combustion

The default heat contents specified in Table 4 are provided for use with sections 95125(a) and (b) of the regulation.

The default carbon dioxide emission factors from stationary combustion on a heat content basis (kg CO_2 / MMBtu) specified in Table 4 and Table 5 are provided for use with sections 95125(a), (c) and (h) of the regulation.

Table 4. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type

Fuel Type	Default Carbon Content	Default Heat Content	Default CO_2 Emission Factor	Default CO_2 Emission Factor
Coal and Coke	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Anthracite	28.26	25.09	2,597.94	103.54
Bituminous	25.49	24.93	2,328.35	93.40
Sub-bituminous	26.48	17.25	1,673.64	97.02
Lignite	26.30	14.21	1,369.32	96.36
Unspecified (Residential/Commercial)	26.00	22.24	2,118.67	95.26
Unspecified (Industrial Coking)	25.56	26.28	2,461.17	93.65
Unspecified (Other Industrial)	25.63	22.18	2,082.89	93.91
Unspecified (Electric Power)	25.76	19.97	1,884.86	94.38
Coke	27.85	24.80	2,530.65	102.04
Natural Gas (By Heat Content)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cub. ft.**	**kg CO_2 / MMBtu**
975 to 1,000 Btu / Standard cubic foot	14.73	n/a	n/a	53.97
1000 to 1,025 Btu / Std cubic foot	14.43	n/a	n/a	52.87
1025 to 1,050 Btu / Std cubic foot	14.47	n/a	n/a	53.02
1050 to 1,075 Btu / Std cubic foot	14.58	n/a	n/a	53.42
1075 to 1,100 Btu / Std cubic foot	14.65	n/a	n/a	53.68
Greater than 1,100 Btu / Std cubic foot	14.92	n/a	n/a	54.67
Unspecified (Weighted U.S. Average)	14.47	1,027	0.0544	53.02

Table 4. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type (continued)

Petroleum Products	kg C / MMBtu	MMBtu / Barrel	kg CO_2 / gallon	kg CO_2 / MMBtu
Asphalt & Road Oil	20.62	6.636	11.94	75.55
Aviation Gasoline	18.87	5.048	8.31	69.14
Distillate Fuel Oil (#1, 2 & 4)	19.95	5.825	10.14	73.10
Jet Fuel	19.33	5.670	9.56	70.83
Kerosene	19.72	5.670	9.75	72.25
LPG (energy use)	17.19	3.861	5.79	62.98
Propane	17.20	3.824	5.74	63.02
Ethane	16.25	2.916	4.13	59.54
Isobutane	17.75	4.162	6.44	65.04
n-Butane	17.72	4.328	6.69	64.93
Lubricants	20.24	6.065	10.71	74.16
Motor Gasoline	19.33	5.218	8.80	70.83
Residual Fuel Oil (#5 & 6)	21.49	6.287	11.79	78.74
Crude Oil	20.33	5.800	10.29	74.49
Naphtha (<401 deg. F)	18.14	5.248	8.30	66.46
Natural Gasoline	18.24	4.620	7.35	66.83
Other Oil (>401 deg. F)	19.95	5.825	10.14	73.10
Pentanes Plus	18.24	4.620	7.35	66.83
Petrochemical Feedstocks	19.37	5.428	9.17	70.97
Petroleum Coke	27.85	6.024	14.64	102.04
Still Gas	17.51	6.000	9.17	64.16
Special Naphtha	19.86	5.248	9.09	72.77
Unfinished Oils	20.33	5.825	10.33	74.49
Waxes	19.81	5.537	9.57	72.58
Biomass-derived Fuels (Solid)	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Wood and Wood Waste (12% moisture content) or other solid biomass-derived fuels	25.60	15.38	1,442.62	93.80
Biomass-derived Fuels (Gas)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cub. ft.**	**kg CO_2 / MMBtu**
Biogas	14.2	Varies	Varies	52.03

Note: Heat content factors are based on higher heating values (HHV).

Source: U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 2.1, Tables A-28, A-31, A-32, A-35, and A-36, except: Heat Content factors for Unspecified Coal (by sector), Coke, Naphtha (<401 deg. F), and Other Oil (>401 deg. F) (from U.S. Energy Information Administration, *Annual Energy Review 2005* (2006), Tables A-1, A-4, and A-5); Heat Content factors for Coal (by type) and LPG and all factors for Wood and Wood Waste, Landfill Gas, and Wastewater Treatment Biogas (from EPA Climate Leaders, Stationary Combustion Guidance (2004), Tables B-1 and B-2).

Table 5. Default Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type for Alternative Fuels	
Fuel Type	**kg CO_2 / MMBtu**
Waste Oil	74
Tires	85
Plastics	75
Solvents	74
Impregnated Saw Dust	75
Other Fossil Based Wastes	80
Dried Sewage Sludge	110
Mixed Industrial Waste	83
Municipal Solid Waste	90.652
Note: Emission factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.	
Source: WBCSD/WRI, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry* Calculation Tool (2004), except: Municipal Solid Waste, (from EIA *Voluntary Reporting of Greenhouse Gases Website* http://www.eia.doe.gov/oiaf/1605/coefficients.html (Accessed October 5, 2007))	

(b) Methane and Nitrous Oxide Emission Factors for Stationary Combustion

The default methane and nitrous oxide emission factors for stationary combustion in Table 6 are provided for use with section 95125(b) of the regulation.

Table 6. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type

Fuel Type	Default CH_4 Emission Factor (g CH_4/ MMBtu)	Default N_2O Emission Factor (g N_2O / MMBtu)
Asphalt	3.0	0.6
Aviation Gasoline	3.0	0.6
Coal	10.0	1.5
Crude Oil	3.0	0.6
Digester Gas	0.9	0.1
Distillate	3.0	0.6
Gasoline	3.0	0.6
Jet Fuel	3.0	0.6
Kerosene	3.0	0.6
Landfill Gas	0.9	0.1
LPG	1.0	0.1
Lubricants	3.0	0.6
MSW	30.0	4.0
Naphtha	3.0	0.6
Natural Gas	0.9	0.1
Natural Gas Liquids	3.0	0.6
Other Biomass	30.0	4.0
Petroleum Coke	3.0	0.6
Propane	1.0	0.1
Refinery Gas	0.9	0.1
Residual Fuel Oil	3.0	0.6
Tires	3.0	0.6
Waste Oil	30.0	4.0
Waxes	3.0	0.6
Wood (Dry)	30.0	4.0

Notes: Heat content factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels and 10 percent lower for gaseous fuels. Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.

Source: Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (2006), Volume 2, Tables 2.2 and 2.3.

(c) Carbon Dioxide Emission Factors for Transportation Fuels

The default carbon dioxide emission factors in Table 7 are provided for use with section 95125(i) of the regulation. These factors may only be used for vehicular emissions and should not be applied to stationary combustion sources.

Table 7. Carbon Dioxide Emission Factors for Transportation Fuels

Fuel	kg CO_2/gallon
Aviation gasoline	8.24
Biodiesel	9.52
CA Low Sulfur Diesel	9.96
CA Reformulated gasoline, 5.7% ethanol	8.55
Crude Oil	10.14
Non-CA Diesel/Diesel No.2	10.05
Ethanol (E85)	6.10
Fischer Tropsch Diesel	9.13
Jet Fuel, Kerosene (Jet A or A-1)	9.47
Jet Fuel, Naphtha (Jet B)	9.24
Kerosene	9.67
Liquefied Natural Gas (LNG)	4.37
Liquefied Petroleum Gas (LPG)	5.92
Methanol	4.10
Motor Gasoline (Non CA and off-road)	8.78
Propane	5.67
Residual Oil	11.67
Fuels With Other Units Of Measure	
Natural Gas (CNG) per therm	5.28
Natural Gas (CNG) per gasoline gallon equivalent	6.86
Hydrogen per kg	0.00
Note: Emission factors are based on complete combustion and high heating value (HHV).	
Source: California Energy Commission, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999* (November 2002); Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2000*, (2001), Table B1, page 140, see http://www.eia.doe.gov/oiaf/1605/ggrpt; propane and butane emission factors and fractions oxidized from U.S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, AP- 42*, Fifth Edition, see http://www.epa.gov/ttn/chief/ap42/index.html. Methanol emission factor is calculated from the properties of the pure compounds; the fraction oxidized is assumed to be the same as for other liquid fuel.	

(d) Methane and Nitrous Oxide Emission Factors for On-Road Mobile Sources

The default methane and nitrous oxide emission factors in Table 8 are provided for use with section 95125(i) of the regulation.

Table 8. Methane and Nitrous Oxide Emission Factors for Mobile Sources by Vehicle and Fuel Type

Vehicle Types/Model Years	CH_4 (g/mile)	N_2O (g/mile)
Passenger Cars - Gasoline		
Model Year 1966-1972	0.22	0.02
Model Year 1973-1974	0.19	0.02
Model Year 1975-1979	0.11	0.05
Model Year 1980-1983	0.07	0.08
Model Year 1984-1991	0.06	0.08
Model Year 1992	0.06	0.07
Model Year 1993	0.05	0.05
Model Year 1994-1999	0.05	0.04
Model Year 2000– present	0.04	0.04
Passenger Cars - Alternative Fuels and Diesel		
CNG Model Year 2000– present	0.04	0.04
LPG Model Year 2000– present	0.04	0.04
E85 Model Year 2000– present	0.04	0.04
Diesel all model years	0.01	0.02
Light Duty Truck (<5750 GVWR*) - Gasoline		
Model Year 1966-1972	0.22	0.02
Model Year 1973-1974	0.23	0.02
Model Year 1975-1979	0.14	0.07
Model Year 1980-1983	0.12	0.13
Model Year 1984-1991	0.11	0.14
Model Year 1992	0.09	0.11
Model Year 1993	0.07	0.08
Model Year 1994-1999	0.06	0.06
Model Year 2000– present	0.05	0.06
Light Duty Truck - Alternative Fuels and Diesel		
CNG Model Year 2000– present	0.05	0.06
LPG Model Year 2000– present	0.05	0.06
E85 Model Year 2000– present	0.05	0.06
Diesel all model years	0.01	0.03

Table 8. Methane and Nitrous Oxide Emission Factors for Mobile Sources by Vehicle and Fuel Type (continued)		
Heavy-Duty Vehicle (>5751 GVWR) - Gasoline	**CH_4 (g/mile)**	**N_2O (g/mile)**
Model Year 1981 and older	0.43	0.04
Model Year 1982-1984	0.42	0.05
Model Year 1985-1986	0.20	0.05
Model Year 1987	0.18	0.09
Model Year 1988-1989	0.17	0.09
Model Year 1990-present	0.12	0.20
Heavy Duty Trucks - Diesel and Alternative Fuels		
Model Year 1966-1982	0.10	0.05
Model Year 1983-1995	0.08	0.05
Model Year 1996 to present	0.06	0.05
CNG, LNG	3.48	0.05
FTD, Biodiesel	0.06	0.05
Motorcycles		
Model Year 1966-1995	0.42	0.01
Model Year 1996-present	0.09	0.01
*GVWR = Gross Vehicle Weight Rating Note: Emission factors are based on complete combustion and high heating value (HHV).		
Source: Derived from California Energy Commissions, *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999* (November 2002).		

(e) Fugitive Carbon Dioxide Emission Factor from Geothermal Power Plants

The default carbon dioxide emission factor for geothermal power plants given in Table 9 is provided for use with section 95111(i) of the regulation.

Table 9. Default Fugitive Carbon Dioxide Emission Factor from Geothermal Power Plants

Fuel Type	kg CO_2 / MMBtu
Geothermal	16.6

Source: Energy Information Administration, *Electric Power Annual with data for 2005*, carbon dioxide uncontrolled emission factors website see http://www.eia.doe.gov/cneaf/electricity/epa/epata3.html (Accessed 10/9/07)

(f) Fugitive Emission Fact ors for Coal Storage

The emission factors for fugitive methane emissions from coal storage in Table 10 are derived from the U.S. EPA Coal Bed Methane Emissions Estimates Database. These factors must be applied as indicated in section 95125(j) of the regulation.

Table 10. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling

Coal Origin			Coal Mine Type	
Coal-Producing Region	**Basin or Coalbed Name**	**State**	**Surface Mines (scf CH_4/ton)**	**Underground Mines (scf CH_4/ton)**
Appalachian	Northern Appalachian	MD, OH, PA, northern WV	16.0	55.8
	Central Appalachian	Eastern KY, TN, VA, southern WV	16.0	107.5
	Warrior	AL	16.0	103.4
Interior	Illinois	IL, IN, western KY	11.1	20.9
Western	Rockies and Southwest Basins	Colorado, New Mexico, Utah	5.0	73.4
All Other States			1.0	13.5

Source: EPA/STAPPA/ALAPCO *Method for Estimating Methane Emissions from Coal Mining*, Volume VIII: Chapter 4, (1999); Exhibit 4.4-2; http://www.p2pays.org/ref/17/ttn/volume08/viii04.pdf, (accessed October 11, 2007).

(g) Coke Burn Rate Material Balance and Conversion Factors

The coke burn rate material balance and conversion factors given in Table 11 are provided for use with section 95113(d)(1)(A) of the regulation.

Table 11. Coke burn rate material balance and conversion factors

	(kg min)/(hr dscm %)	(lb min)/(hr dscf %)
K_1	0.2932	0.0186
K_2	2.0830	0.1303
K_3	0.0994	0.0062

Source: US EPA Title 40 CFR 63.1564

(h) Nitrous Oxide Emission Factor for Wastewater Treatment

The method to derive an emission factor for fugitive nitrous oxide emissions from wastewater treatment specified below is based on 2006 IPCC guidelines. This method is provided for use with section 95113(e)(1) of the regulation.

Table 12. Default MCF Values for Industrial Wastewater

Type of Treatment and Discharge Pathway or System	Comments	MCF	Range
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Treated			
Aerobic treatment plant	Well maintained, some CH4 may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 meters	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 meters	0.8	0.8 – 1.0

Source: Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (2006), Volume 5, Waste, Chapter 6: Wastewater Treatment and Discharge. Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds).

MCF = methane correction factor – the fraction of waste treated anaerobically

B_0 = maximum CH_4 producing capacity (kg CH_4/kg COD)
Default factor = 0.25 kg CH_4/kg COD

COD = chemical oxygen demand (kg COD/m^3)
Default factor = 1.0 kg COD/m^3

EF_{N2O} = 0.005 kg N_2O-N/kg-N (Range 0.0005 – 0.25)

(i) Gas Service Components Fugitive Emission Factors

The information presented in Table 13 is provided for use with section 95113(e)(4) as part of the method to determine fugitive methane emissions from fuel gas systems.

Table 13. Gas Service Components Fugitive Emissions

Component Type / Service Type	Default Zero Factor (kg/hr)	Correlation Equation (kg/hr)	Pegged Factor (kg/hr)	
			10,000 ppmv	100,000 ppmv
Valves	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064	0.138
Pump seals	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089	0.610
Others	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082	0.138
Connectors	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030	0.034
Flanges	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095	0.095
Open-ended lines	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033	0.082

Source: California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, February 1999, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board

6. Method for Calculating Emissions of High Global Warming Potential Compounds

Provided below is the fugitive SF_6 emissions calculation methodology created by the U.S. EPA SF_6 Emission Reduction Partnership for Electric Power Systems. Operators shall use this approach or a service log for estimating fugitive emissions of high global warming potential compounds, including SF_6, HFCs, and PFCs, as specified in sections 95111(f)-(g) of the regulation. The reporting form that follows the method below is for illustrative purposes.

SF6 EMISSIONS INVENTORY REPORTING METHOD AND FORM

This worksheet is based on the **mass-balance method**. The mass-balance method works by tracking and systematically accounting for all operator uses of SF6 during the reporting year. The quantity of SF6 that cannot be accounted for is then assumed to have been emitted to the atmosphere. The method has four subcalculations (A-D), a final total (E), and an optional emission rate calculation (F) as follows:

A. **Change in Inventory**. This is the difference between the quantity of SF6 in storage at the beginning of the year and the quantity in storage at the end of the year. The "quantity in storage" includes SF6 gas contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not refer to SF6 gas held in operating equipment. The change in inventory will be negative if the quantity of SF6 in storage increases over the course of the year.

B. **Purchases/Acquisitions of SF6**. This is the sum of all the SF6 acquired from other entities during the year either in storage containers or in equipment.

C. **Sales/Disbursements of SF6**. This is the sum of all the SF6 sold or otherwise disbursed to other entities during the year either in storage containers or in equipment.

D. **Change in Total Nameplate Capacity of Equipment**. This is the net increase in the total volume of SF6-using equipment during the year. Note that "total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. This term accounts for the fact that if new equipment is purchased, the SF6 that is used to charge that new equipment should not be counted as an emission. On the other hand, it also accounts for the fact that if the amount of SF6 recovered from retiring equipment is less than the nameplate capacity, then the difference between the nameplate capacity and the recovered amount has been emitted. This quantity will be negative if the retiring equipment has a total nameplate capacity larger than the total nameplate capacity of the new equipment.

E. **Total Annual Emissions**. This is the total amount of SF6 emitted over the course of the year, based on the information provided above. The amount is presented both in pounds of SF6 and in metric tonnes of CO2-equivalent, that is, the quantity of carbon dioxide emissions that would have the same impact on the climate as the quantity of SF6 emitted. Because SF6 has 23,900 times the ability of carbon dioxide to trap heat in the atmosphere on a pound-for-pound basis, 1 pound of SF6 is equivalent to nearly 11 metric tonnes of carbon dioxide.

F. **Emission Rate (optional)**. By providing the total nameplate capacity of all the electrical equipment in your facility at the end of the year, you can obtain an estimate of the emission rate of your facility's equipment (in percent per year).
The emission rate is equal to the total annual emissions divided by the total nameplate capacity.

SF_6 Emissions Reduction Partnership for Electric Power Systems

Annual Reporting Form

Name:		Company Name:	
Title:		Report Year:	
Phone:		Date Completed:	

Change in Inventory (SF_6 contained in cylinders, not electrical equipment)

Inventory (in cylinders, not equipment)	AMOUNT (lbs.)	Comments
1. Beginning of Year		
2. End of Year		
A. Change in Inventory (1 - 2)	-	

Purchases/Acquisitions of SF_6

	AMOUNT (lbs.)	Comments
3. SF_6 purchased from producers or distributors in cylinders		
4. SF_6 provided by equipment manufacturers with/inside equipment		
5. SF_6 returned to the site after off-site recycling		
B. Total Purchases/Acquisitions (3+4+5)	-	

Sales/Disbursements of SF_6

	AMOUNT (lbs.)	Comments
6. Sales of SF_6 to other entities, including gas left in equipment that is sold		
7. Returns of SF_6 to supplier		
8. SF_6 sent to destruction facilities		
9. SF_6 sent off-site for recycling		
C. Total Sales/Disbursements (6+7+8+9)	-	

Change in Nameplate Capacity

	AMOUNT (lbs.)	Comments
10. Total nameplate capacity (proper full charge) of new equipment		
11. Total nameplate capacity (proper full charge) of retired or sold equipment		
D. Change in Capacity (10 - 11)	-	

Total Annual Emissions

	lbs. SF_6	Tonnes CO_2 equiv. (lbs.SF_6x23,900/2205)
E. Total Emissions (A+B-C-D)	-	-

Emission Rate (optional)

	AMOUNT (lbs.)	Comments
Total Nameplate Capacity at End of Year		
	PERCENT (%)	
F. Emission Rate (Emissions/Capacity)	-	

ATTACHMENT B

Non-Regulatory
Table of Contents and Matrix of Methodologies
for the Proposed Regulation

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TABLE

MATRIX OF METHODOLOGIES BY SECTOR

Matrix of Methodologies by Sector

	Type of Facility					
	Cement Plants	**Electrical Generating Facilities & Retail Providers**	**Cogeneration**	**Petroleum Refineries**	**Hydrogen Plants**	**General Stationary Combustion**
Basic Sector-specific Reporting Requirements	95110	95111	95112	95113	95114	95115
Methods to Estimate Emissions From Combustion						
Fuel Measurement Based Methods						
CO_2 Emissions From Combustion (by fuel type)						
Associated Gas	95125(e)	95125(e)	95125(e)			95125(e)
Biogas	95125(c) or (d)	95125(c) or (d)	95125(c) or (d)			95125(a),(c),(d) or (h)
Biomass Fuels	95125(a) or (h)(3)	95125(h)	95125(h)			95125(a),(c),(d) or (h)
Coal	95125(d)	95125(d)	95125(d)			95125(a),(c),(d) or (h)
Distillate Fuel (Diesel)	95125(c) or (d)	95125(c) or (d)	95125(c) or (d)	95125(a)	95125(a)	95125(a),(c),(d) or (h)
Gasoline	95125(c) or (d)	95125(c) or (d)	95125(c) or (d)	95125(a)	95125(a)	95125(a),(c),(d) or (h)
Landfill Gas	95125(c) or (d)	95125(c) or (d)	95125(c) or (d)			95125(a),(c),(d) or (h)
Liquefied Petroleum Gas (LPG)	95125(c) or (d)	95125(c) or (d)	95125(c) or (d)	95125(a)	95125(a)	95125(a),(c),(d) or (h)
Municipal Solid Waste	95125(a) or (h)(3)	95125(h)	95125(h)			95125(a),(c),(d) or (h)
Natural Gas	95125(c) or (d)	95125(c) or (d)	95125(c) or (d)	95125(c) or (d)	95125(c) or (d)	95125(a),(c),(d) or (h)
Petroleum Coke	95125(d)	95125(d)	95125(d)			95125(a),(c),(d) or (h)
Process Gas	95125(e)	95125(e)	95125(e)			95125(e)
Refinery Fuel Gas	95125(e)	95125(e)	95125(e)	95125(e)	95125(e)	95125(e)
Residual Fuel Oils	95125(c) or (d)	95125(c) or (d)	95125(c) or (d)	95125(a)	95125(a)	95125(a),(c),(d) or (h)
Still Gas	95125(e)	95125(e)	95125(e)			95125(e)
Other (Including "Alternative Fuels")	95125(c)					95125(a),(c),(d) or (h)
N_2O and CH_4 Emissions From Combustion (for all fuel types)	95125(b)	95125(b)	95125(b)	95125(b)	95125(b)	95125(b)
Methods Which May Combine Process and Combustion Emissions						
Continuous Emissions Monitoring Method	95125(g)	95125(g)	95125(g)		95125(g)(6)	95125(g)
Hydrogen Plant Fuel and Feedstock Mass Balance Method					95114(b)(2)	

Matrix of Methodologies by Sector (Continued)

	Type of Facility					
	Cement Plants	**Electrical Generating Facilities & Retail Providers**	**Cogeneration**	**Petroleum Refineries**	**Hydrogen Plants**	**General Stationary Combustion**
Methods to Estimate Process Emissions & Flaring Emissions						
CO_2 From Cement Process Emissions	95110(c)					
CO_2 From Acid Gas Scrubbers		95111(e)	95111(e)			
CO_2 From Catalytic Cracking				95113(b)(1)		
CO_2 From Catalyst Regeneration				95113(b)(2)		
CO_2, CH_4, N_2O From Process Vents				95113(b)(3)	95113(b)(3)	
CO_2, CH_4 From Asphalt Production				95113(b)(4)		
CO_2 From Sulfur Recovery				95113(b)(5)	95113(b)(5)	
CO_2 From Flaring				95113(d)	95113(d)	
CO_2 Process Emissions From Hydrogen Plants					95114(b)	
Methods to Estimate Fugitive Emissions						
CH_4 Emissions from Coal Storage	95125(j)	95125(j)	95125(j)			
Fugitive SF_6 Emissions		95111(f)	95111(f)			
Fugitive HFC Emissions		95111(g)	95111(g)			
Fugitive CO_2 Emissions from Geothermal Generating Facilities		95111(i)	95111(i)			
CH_4 and N_2O From Wastewater Treatment				95113(c)(1)	95113(c)(1)	
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CH_4 Fugitive Emissions From Gas Service Components				95113(c)(4)	95113(c)(4)	
Secondary Emissions Accounting Methods: Indirect Energy Usage, Electricity Transactions, Plant Efficiency and Cogeneration Emission Attribution						
Indirect Energy Usage Estimation Methods						
Indirect Electricity Usage	95125(k)		95125(k)	95125(k)	95125(k)	95125(k)
Indirect Thermal Energy Usage	95125(l)			95125(l)	95125(l)	95125(l)
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Cement Plant Efficiency Metric	95110(e)					

CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC MEETING TO CONSIDER THE APPROVAL OF THE 1990 STATEWIDE GREENHOUSE GAS EMISSIONS LEVEL AND 2020 EMISSIONS LIMIT

The Air Resources Board (the Board or ARB) will conduct a public meeting at the time and place noted below to consider the approval of the 1990 statewide greenhouse gas emissions level and 2020 emissions limit.

DATE: December 6, 2007

TIME: 9:00 a.m.

PLACE: Air Resources Board
Auditorium
9530 Telstar Avenue
El Monte, California 91731

This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., December 6, and may continue at 8:30 a.m., December 7. This item may not be considered until December 7. Please consult the agenda for the meeting, which will be available at least 10 days before December 6, to determine the day on which this item will be considered.

For individuals with sensory disabilities, this document is available in Braille, large print, audiocassette or computer disk. Please contact ARB's Disability Coordinator at (916) 323-4916 by voice or through the California Relay Services at 711, to place your request for disability services. If you are a person with limited English and would like to request interpreter services, please contact ARB's Bilingual Manager at (916) 323-7053.

The Global Warming Solutions Act of 2006 requires ARB to determine the statewide greenhouse gas (GHG) emissions level in 1990 and approve a statewide GHG emissions limit equivalent to that level, to be achieved by 2020. ARB staff is recommending that the Board approve 427 million metric tonnes of carbon dioxide equivalent (MMT CO2e) as the total statewide aggregated GHG 1990 emissions level and 2020 emissions limit.

ARB staff undertook an extensive review of the methods and data used to develop a statewide GHG emissions inventory for 1990. ARB staff worked closely with numerous local, state, and federal environmental agencies to obtain critical data to determine the 1990 emissions level. ARB staff also held over a dozen technical discussions and workshops to obtain public and stakeholder input on emissions estimation methods and updated data.

At the Board meeting, ARB staff will present the results of its review and the basis for the staff recommendation. A staff report on the emission estimation methodologies and data used is available for review. Copies of the report may be obtained from the Board's Public Information Office,1001 "I" Street, 1st Floor, Environmental Services Center, Sacramento, California 95814, (916) 322-2990. The report may also be obtained from ARB's internet site at http://www.arb.ca.gov/cc/ccei/ccei.htm

Interested members of the public may also present comments orally or in writing at the meeting, and in writing or by email before the meeting. To be considered by the Board, written comments submissions not physically submitted at the meeting must be received **no later than 12:00 noon, Wednesday, December 5, 2007,** and 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

Facsimile submittal: (916) 322-3928

Please note that under the California Public Records Act (Government Code section 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 30 copies of any written submission. Also, ARB requests that written and email statements be filed at least 10 days prior to the meeting so that ARB staff and Board members have time to fully consider each comment. Further inquiries regarding this matter should be directed Webster Tasat, Manager, Emission Inventory Analysis Section, 1001 I Street, Sacramento, California 95814, (916) 323-4950.

CALIFORNIA AIR RESOURCES BOARD

James N. Goldstene
Executive Officer

Date: November 20, 2007

California Environmental Protection Agency
AIR RESOURCES BOARD

Staff Report

California 1990 Greenhouse Gas Emissions Level and 2020 Emissions Limit

Public Release Date:
November 16, 2007

This document has been prepared by the staff of the California Air Resources Board. Publication does not signify that the contents reflect the views and policies of the Air Resources Board. The Air Resources Board will consider this document at a noticed public meeting tentatively scheduled for December 6-7, 2007.

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Acknowledgements

Staff of the Air Resources Board wishes to express their appreciation to the many stakeholders that were an integral part of developing the 1990 emissions level through workshops, technical discussions, and conference calls. The following organizations in particular were critical to the success of this effort, both in their technical advice and their constructive participation throughout the process: California Energy Commission; California Integrated Waste Management Board; California Public Utilities Commission; California Department of Forestry & Fire Protection; U.S. Environmental Protection Agency; U.S. Energy Information Administration; U.S.D.A. Forest Service; California Climate Action Registry; Lawrence Berkeley National Lab; University of California-Berkeley; Western States Petroleum Association; Waste Management, Inc.; Los Angeles County Sanitation District; Portland Cement Association; Californians Against Waste; Natural Resources Defense Council; Environmental Defense; and, Sacramento Municipal Utilities District.

Staff Report

California 1990 Greenhouse Gas Emissions Level and 2020 Emissions Limit

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EXECUTIVE SUMMARY

The Global Warming Solutions Act of 2006 (the Act or AB 32, Nunez, Statutes of 2006, chapter 488) requires the Air Resources Board (ARB or Board) to determine the statewide greenhouse gas emissions level in 1990 and to approve a statewide greenhouse gas emissions limit, equal to that level, to be achieved by 2020. ARB staff is recommending that the Board approve 427 million metric tonnes of carbon dioxide equivalent (MMTCO2e) as the total statewide aggregated greenhouse gas 1990 emissions level and 2020 emissions limit.

This staff report discusses the development of the 1990 statewide emissions level and provides a summary of the key emissions sources, the methodologies used to calculate the emissions, and the sources of data. More detailed documentation is provided on-line at http://www.arb.ca.gov/cc/ccei/emsinv/emsinv.htm.

The Act establishes a comprehensive program to reduce greenhouse gases by 2020 and identifies several major requirements that ARB is or will be implementing:

- Adopt and implement a list of discrete and early action greenhouse gas reduction measures (done);
- Approve a statewide 1990 emissions level that becomes California's statewide 2020 emissions limit (due January 2008);
- Adopt mandatory greenhouse gas reporting rules for significant greenhouse gas sources (due January 2008);
- Adopt a Scoping Plan for greenhouse gas emission reductions to achieve the 1990 emissions level by 2020 (due January 2009); and,
- Adopt emission regulations to achieve the maximum technologically feasible and cost-effective reductions.

In January 2007, Assembly Bill 1803 transferred responsibility for developing and maintaining the State's greenhouse gas inventory from the California Energy Commission (CEC) to ARB. Using the CEC greenhouse gas inventory as a starting point, ARB staff determined the State's 1990 greenhouse gas emissions level by conducting a comprehensive review of all greenhouse gas emitting sectors. The seven sectors are: Transportation, Electricity Generation, Industrial, Residential, Agriculture, Commercial, and Forestry.

ARB staff gathered data from State and federal agencies, international organizations, and California industries to estimate the total statewide 1990 greenhouse gas emissions level. California facility-specific information for 1990 emissions was used where available.

Upon approval by the Board, the 1990 emissions level becomes the 2020 emissions limit, which represents an aggregated emissions limit for California.

For purposes of the AB 32 Scoping Plan, it serves as the target to be achieved by 2020.

For purposes of Scoping Plan development, ARB staff has estimated the State's greenhouse gas emissions in 2020 without the implementation of additional greenhouse gas reduction strategies. This 2020 "business-as-usual" estimate is approximately 600 MMTCO2e and is based on economic forecasts that use growth factors to project emissions. The difference between the 2020 business-as-usual estimate and the 1990 emissions level is California's emission reduction goal. The 2020 business-as-usual forecast will be further refined as the Scoping Plan is developed.

The 2020 emissions limit, as defined by the 1990 emissions level, remains in effect until amended by the Board. If additional information becomes available that would significantly alter the total emissions for 1990, staff will bring a revised 1990 emissions level back to the Board for consideration.

I. STAFF RECOMMENDATION

The Global Warming Solutions Act of 2006 (AB 32, Nunez, Statutes of 2006, chapter 288) requires the Air Resources Board (ARB or Board) to approve by January 1, 2008, the statewide greenhouse gas emissions limit for 2020 based on the 1990 emissions level. Over the past year, ARB staff has undertaken a comprehensive review and update of the 1990 emissions estimates using the best available scientific, technical, and economic information. These emissions estimates were developed through an extensive public process, including technical workshops.

ARB staff has estimated the statewide 1990 emissions level to be 427 MMTCO2e and is recommending the Board approve this level as the statewide 1990 greenhouse gas emissions level to be achieved by 2020. Once adopted, the 2020 emissions limit will remain in effect until amended. If new information becomes available that would significantly alter total emissions for 1990, staff will bring a revised 1990 emissions level to the Board for consideration.

II. BACKGROUND

The Global Warming Solutions Act of 2006 (the Act) establishes a comprehensive program to realize real, quantifiable, and cost-effective reductions in greenhouse gas emissions by 2020. The Act directs ARB to:

- Adopt and implement a list of discrete and early action greenhouse gas reduction measures (done);
- Approve a statewide 1990 emissions level that becomes California's statewide 2020 emissions limit (due January 2008);
- Adopt mandatory greenhouse gas reporting rules for significant greenhouse gas sources (due January 2008);
- Adopt a Scoping Plan for greenhouse gas emission reductions to achieve the 1990 emissions level by 2020 (due January 2009); and,
- Adopt emission regulations to achieve the maximum technologically feasible and cost-effective reductions.

This staff report discusses the development of the 1990 emissions level that sets the statewide greenhouse gas emissions limit for 2020. It is an aggregated statewide limit that provides the target level that must be achieved through regulatory measures, market mechanisms or other actions that will be contained in the Scoping Plan. The Scoping Plan is scheduled to be taken to the Board in late 2008.

III. OVERVIEW OF THE DEVELOPMENT OF THE 1990 EMISSIONS LEVEL

The statewide 1990 greenhouse gas emissions level of 427 MMTCO2e is based on the net amount of greenhouse gases emitted to and removed from the air. The gross statewide emissions in 1990 were 433 MMTCO2e with forestry sinks offsetting approximately 7 MMTCO2e, resulting in net emissions to the atmosphere of approximately 427 MMTCO2e (see Table 2). The 1990 emissions level is a compilation or inventory of the amount and type of greenhouse gases emitted by different sources on an annual basis. In addition to setting California's 1990 emissions level and 2020 emissions limit, ARB now has overall responsibility for the State's annual greenhouse gas emissions inventory.

In September 2000, the Legislature passed Senate Bill 1771. It required the California Energy Commission (CEC) to determine the statewide greenhouse gas emissions inventory by January 2002 and update it every five years thereafter. In 2006, Assembly Bill 1803 transferred responsibility for updating the statewide greenhouse gas inventory to ARB commencing January 1, 2007.

In January 2007, ARB staff began an intensive review of the CEC's California greenhouse gas emissions inventory for the years 1990 to 2004, with particular focus on the 1990 emissions estimates. Staff has updated and evaluated the 1990 emissions inventory and ensured its consistency with national and international guidelines for greenhouse gas inventories.

The remainder of this section summarizes the key components of the 1990 emissions inventory. A supplemental document titled "California Greenhouse Gas Emission Inventory, 1990 to 2004" will discuss emissions estimates for 1990 to 2004.

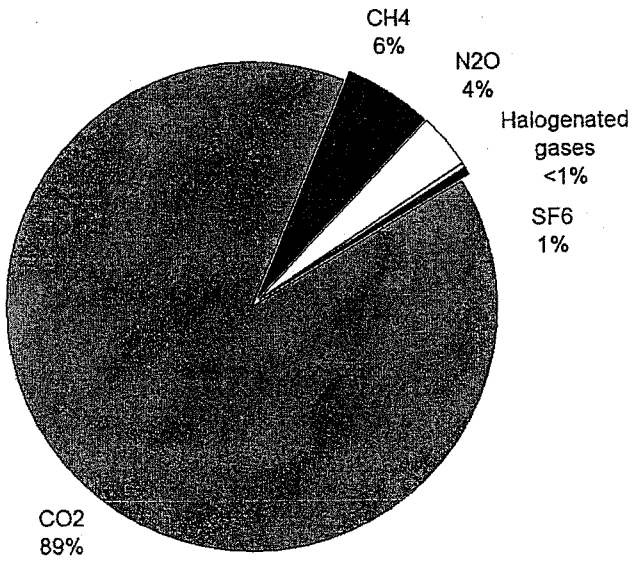
A. Which gases are included?

Pursuant to the Act, the inventory includes the following Kyoto greenhouse gases: carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs). These greenhouse gases are referenced in the international guidance on the development of national inventories provided by the Intergovernmental Panel on Climate Change (IPCC), the authoritative scientific body on climate change.

The greenhouse gases included in the inventory absorb infrared radiation, directly impacting the atmosphere's ability to trap heat. Three of these greenhouse gases, CO2, CH4, and N2O, may be emitted naturally or through human activities (e.g., the combustion of fossil fuels). The other three, SF6, HFCs, and PFCs, are synthetically produced for industrial purposes.

Almost 90 percent of the total greenhouse gas emissions in the 1990 inventory were in the form of CO2, as shown in Figure 1. Carbon dioxide accounted for 389 MMTCO2e of the total statewide gross greenhouse gas emissions of 433 MMTCO2e. Gross greenhouse gas emissions estimates only include the greenhouse gases emitted to the atmosphere, and exclude removals from the atmosphere. The remaining emissions were comprised of CH4, N2O, halogenated gases (including substitutes for ozone-depleting substances (ODS)), and SF6. Methane and N2O emissions totaled 24.9 MMTCO2e and 16.1 MMTCO2e, respectively. Emissions of SF6 were 2.6 MMTCO2e. Halogenated gas emissions were minimal in 1990, estimated at approximately 0.6 MMTCO2e. Many of the halogenated gases are substitutes for ODS, which are being phased out under the Montreal Protocol on Substances that Deplete the Ozone Layer. Because the Montreal Protocol came into force only shortly beforehand in 1989, emissions of ODS substitutes were relatively small in 1990.

Figure 1. 1990 Gross Emissions by Greenhouse Gas



B. Which global warming potentials are used?

Each greenhouse gas has a different capacity to trap heat in the atmosphere, with some more effective at trapping heat than others. To account for this difference, IPCC developed the metric of a global warming potential (GWP) for each gas. The GWP allows comparison of the global warming influence of different greenhouse gases relative to CO2. Total greenhouse gases can then be expressed as CO2 equivalents or CO2e.

In developing the greenhouse gas inventory for 1990, staff used the GWPs in IPCC's Second Assessment Report for consistency with national and international inventories. All international inventories, including the U.S. inventory, use GWPs from the Second Assessment Report per international

consensus (USEPA 2007). The GWPs used to estimate the 1990 emissions level are referenced in Table 1.

Table 1. Global Warming Potentials (GWPs)
IPCC Second Assessment Report (SAR)

Greenhouse Gas	SAR GWP (100 years)
CO2	1
CH4	21
N2O	310
HFC-23	11,700
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-32	650
CF4	6,500
C2F6	9,200
SF6	23,900

Source: IPCC Second Assessment Report

Since GWPs are indexed to CO2, they allow for the conversion of different greenhouse gas emissions into the same emission unit, carbon dioxide equivalents (CO2e). Carbon dioxide equivalents represent the total impact (radiative forcing) of greenhouse gases in the atmosphere, making it possible to determine the climate change impact of one greenhouse gas versus another. The 1990 greenhouse gas emissions level is expressed in total CO2e. It is calculated as follows:

CO2 Equivalent in million metric tonnes =
(Million metric tonnes of a GHG emitted)(GWP of the GHG)*

C. What types of emissions are included?

The inventory includes emissions of the six greenhouse gases from all known anthropogenic and biogenic sources within California, as well as emissions from imported electricity and transmission and distribution line losses as required by the Act. The total emissions for any given year is the net sum expressed in CO2e emissions to the atmosphere ("positive" emissions) and removals from the atmosphere ("negative" emissions) due to sequestration of carbon by forests and rangelands within the State's boundaries.

Anthropogenic emissions are emissions resulting directly from human activities, such as the combustion of fuels in transportation and industrial activities, as well as process emissions from industrial activities. They are also the result of human influence on natural processes and processes subject to human control. The burning of fossil fuels is the largest single source of anthropogenic greenhouse gas emissions in California. Because increases in anthropogenic greenhouse

gas emissions have substantially increased atmospheric greenhouse gas concentrations, anthropogenic emissions are the primary focus of the inventory (IPCC 2007).

Biogenic emissions are emitted as part of the natural biogeochemical cycling of carbon. These emissions include, for example, CO2 released as plants decompose or burn. Natural processes, such as photosynthesis, remove CO2 from the atmosphere and may store carbon in plant tissues for long periods of time (sequestration). In the 1990 inventory, forest-related biogenic emissions and removals are tracked in the Forestry sector. The difference between the biogenic CO2 emissions to and removals from the atmosphere, known as the net flow of atmospheric CO2, indicates whether Forestry is net source or sink of CO2. Biogenic CO2 flux estimates, or the net flow of atmospheric CO2, are detailed in Appendix B.

D. What key sectors and categories were reviewed and updated?

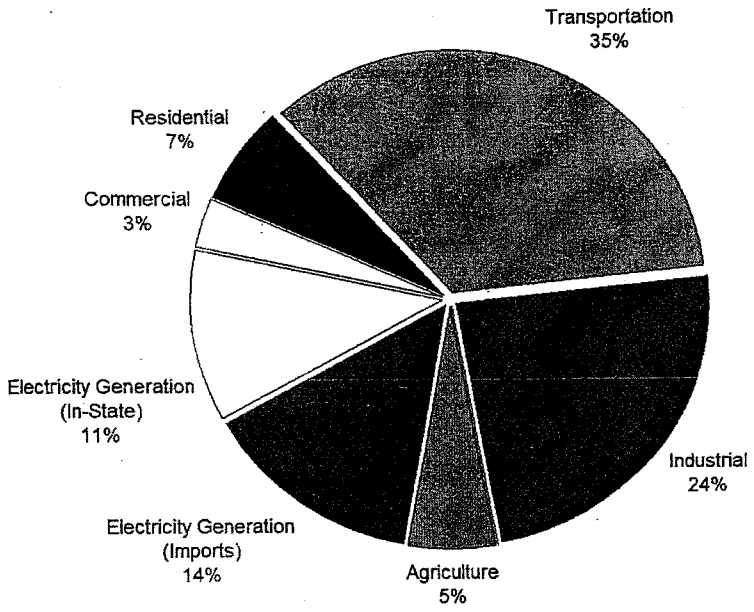
The 1990 emissions level is the sum total of emissions and removals from all sectors and categories in the inventory. The inventory is divided into seven broad sectors defined by areas of economic activity within California. These sectors include: Agriculture; Commercial; Electricity Generation; Forestry; Industrial; Residential; and, Transportation. Each sector contains different types of emission sources called categories. For example, the Industrial sector contains the cement, landfills, and petroleum refining categories. Roughly 85 percent of California's greenhouse gas emissions in 1990 can be found in three sectors: Electricity Generation, Industrial and Transportation.

Staff primarily focused their review and update efforts on five sectors (Agriculture, Electricity Generation, Forestry, Industrial, and Transportation) and three categories within the Industrial sector (cement, landfills, and petroleum refining). Emissions from all seven sectors are listed below in Table 2 and Figure 2. A detailed discussion of the review of the seven sectors is described in Section IV.

Table 2. Greenhouse Gas Emissions by Sector in 1990[1]
(433 MMTCO2e Gross Emissions)

Sector	Total Emissions (MMTCO2e)	Percent of Total Gross Emissions
Agriculture	**23.4**	**5%**
Commercial	**14.4**	**3%**
Electricity Generation	**110.6**	**26%**
In-State	*49.0*	*11%*
Imports	*61.6*	*14%*
Forestry (excluding sinks)	**0.2**	**<1%**
Industrial	**103.0**	**24%**
Cement	*8.1*	*2%*
Landfills	*6.3*	*1%*
Petroleum Refining	*32.8*	*8%*
Residential	**29.7**	**7%**
Transportation	**150.7**	**35%**
Forestry Sinks	**- 6.7**	**--**

Figure 2. 1990 Greenhouse Gas Emissions by Sector[2]
(427 MMTCO2e Net Emissions)



The majority of 1990 emissions are tied to fuel use activities, ranging from transportation to electricity generation to heating buildings. In fact, emissions from fuel combustion comprise more than 80 percent of overall 1990 statewide

[1] The remaining 1.3 MMTCO2e are from unspecified fuel combustion and ODS substitute use, which could not be attributed to an individual sector. Percents may not total 100 due to rounding.
[2] Percents do not total 100. Less than one percent of the inventory is due to unspecified fuel combustion and ODS substitutes, which is not attributed to an individual sector (1.3 MMTCO2e in 1990).

greenhouse gas emissions. The primary fuels combusted were natural gas and gasoline.[3] In-state Electricity Generation, Residential and Industrial sectors accounted for almost 90 percent of the natural gas combusted statewide in 1990, while the Transportation sector consumed almost all (98 percent) of the State's gasoline in 1990.

California's economy and population have grown since 1990, resulting in increases in greenhouse gas emissions for some sectors. Table 3 and Figure 3 reflect the relative contributions of each sector to the State's overall greenhouse gas emissions in 2004.

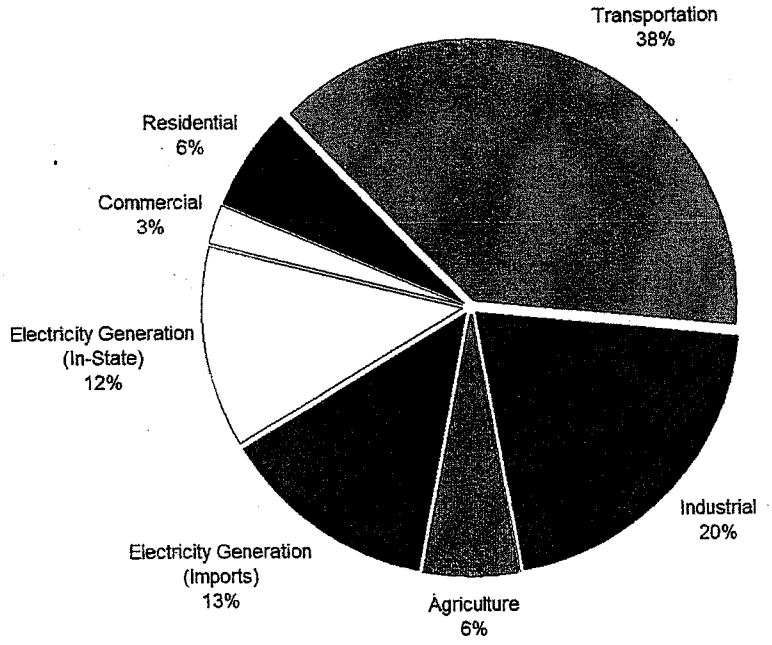
Table 3. Greenhouse Gas Emissions by Sector in 2004[4]
(484 MMTCO2e Gross Emissions)

Sector	Total Emissions (MMTCO2e)	Percent of Total Gross Emissions
Agriculture	**27.9**	**6%**
Commercial	**12.8**	**3%**
Electricity Generation	**119.8**	**25%**
In-State	*58.5*	*12%*
Imports	*61.3*	*13%*
Forestry (excluding sinks)	**0.2**	**<1%**
Industrial	**96.2**	**20%**
Cement	*9.8*	*2%*
Landfills	*5.6*	*1%*
Petroleum Refining	*34.9*	*7%*
Residential	**29.1**	**6%**
Transportation	**182.4**	**38%**
Forestry Sinks	***- 4.7***	*--*

[3] Comparison among fuels uses heat content (e.g., BTUs/scf natural gas; BTUs/gal gasoline) as a common metric among different fuels. Heat content factors are primarily from the California Energy Balance (CALEB) database, EIA and U.S. EPA.

[4] The remaining 16.0 MMTCO2e are from unspecified fuel combustion and ODS substitute use, which is not attributed to an individual sector. Percents may not total 100 due to rounding.

Figure 3. 2004 Greenhouse Gas Emissions by Sector[5]
(480 MMTCO2e Net Emissions)



E. How does the proposed 1990 emissions estimate differ from previous California estimates?

The 1990 emissions level is based on the most recent data and methodologies available. The CEC and Climate Action Team (CAT) also produced estimates of the 1990 emissions level based on the best available data at the time their estimates were made. The CEC estimated the level to be 413 MMTCO2e (duVair 2007). Per Executive Order S-3-05, the CAT, which is made up of representatives from several state agencies, was required to implement greenhouse gas emission reduction programs and report on the progress made toward meeting the statewide targets specified in S-3-05. The CAT sponsored development of a 1990 level using similar estimation methods and data sources to the CEC, with some slight differences in the input data. The CAT's estimated 1990 level was 426 MMTCO2e, which is similar to ARB's updated 1990 level (CAT 2006).

Staff was able to characterize the CEC inventory using similar sectors and categories as the ARB inventory. However, it was not possible to do this same characterization with the available inventory information from the CAT report. Table 4 therefore presents a comparison of only the ARB and CEC inventory emissions estimates.

[5] Percents do not total 100. Roughly three percent of the inventory is due to unspecified fuel combustion and ODS substitute use, which is not attributed to an individual sector (16.0 MMTCO2e in 2004).

Table 4. Differences in ARB and CEC 1990 Emissions Estimates for Sectors and Key Categories

Sector	1990 Emissions (MMTCO2e)	
	ARB	CEC
Agriculture	**23.4**	**31.1**
Commercial	**14.4**	**15.3**
Electricity Generation	**110.6**	**89.2**
In-State	*49.0*	*45.2*
Imports	*61.6*	*44.0*
Forestry (excluding sinks)	**0.2**	**0.2**
Industrial	**103.0**	**79.5**
Cement	*8.1*	*4.8*
Landfills	*6.3*	*8.1*
Petroleum Refining	*32.8*	*27.9*
Residential	**29.7**	**29.6**
Transportation	**150.7**	**177.8**

While the numbers are similar, these estimates have important differences. Emissions from individual sectors differ between CEC and ARB estimates by up to 30 percent due to updated data, methodologies, and differences in included and excluded emissions. Staff treated carbon stored in landfills differently than CEC by separately tracking stored carbon instead of considering it an emission sink within a landfill. In addition, the ARB estimate only includes intrastate aviation, whereas the CEC and CAT estimates include both interstate and intrastate flights. Staff also included emissions from international shipping and related port activities in California waters, whereas the CEC and CAT excluded all emissions from international ships. If ARB treated these sectors in the same manner as the CEC, an additional 7 MMTCO2e would be added to the updated 1990 emissions level.

Additional details on differences between the CEC's and ARB's estimates of 1990 emissions are described in Section IV of the report.

F. Is the inventory consistent with international and national guidelines?

The 1990 California inventory is consistent with international and national guidelines and protocols to the greatest extent possible. Consistency maximizes the comparability of the inventory with inventories from other states and nations. This is important to facilitate the future linkage of California's program with regional, national, and international greenhouse gas emission reduction programs.

IPCC develops the standard international guidance for emissions inventories. Nations that have adopted the United Nations Framework Convention on Climate Change must prepare and report their emissions and sinks of CO2, CH4, N2O,

SF6, PFCs, and HFCs using IPCC methodologies to ensure comparability among national inventories.

The IPCC guidelines delineate the sectors and processes for which nations must report their anthropogenic emissions and sinks, and how they should report these emissions. They also describe different methodologies to estimate both emissions and uncertainties, depending on the available data sources. The guideline documents include: *The Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/OECD/IEA 1997); *Good Practice Guidance and Uncertainty Management in National Greenhouse Inventories* (IPCC 2000); and, *Good Practice for Land Use, Land-Use Change and Forestry* (IPCC 2003), among others. IPCC recently published updated guidelines to incorporate new sources, additional greenhouse gases, and improved methodologies, *2006 Guidelines for National Greenhouse Gas Inventories* (IPCC/UNEP/WMO 2006).

The U.S. EPA is the lead agency for preparing and developing the national greenhouse gas inventory. The U.S. EPA supplements the widely applicable IPCC methodologies with more U.S.-specific and/or updated methodologies and data as feasible, and uses published emission factors and activity data when available.

ARB staff used the IPCC guidelines for its overall approach and sector-specific guidance in developing the 1990 inventory. The guidelines allow for use of state-specific data and methodologies rather than the more generic international ones when available. Staff used California-specific data and methodologies, as appropriate.

International guidance also recommends excluding bunker fuel emissions for all international aviation flights and marine vessel voyages from emissions inventories (IPCC/UNEP/WMO 2006). In an effort to be consistent, we propose to exclude these emissions from the 1990 emissions level, with the exception of marine bunker fuel use in California waters. As discussed above, we are also proposing to exclude greenhouse gas emissions from interstate flights, which is consistent with the international approach of including only those flights within a jurisdiction's borders.

California's inventory differs from the IPCC guidelines and U.S. EPA greenhouse gas inventory in two ways. The Act requires that ARB include imported electricity in the 1990 inventory. International and the U.S. inventories do not. The proposed inventory also contains emissions from all ships, including internationally-flagged ships, occurring within California waters provided that either their origin or destination is a California port.[6]

[6] For purposes of calculating emissions from ships, California waters extend to 24 nautical miles from the coast.

G. What was the review and update process?

Staff updated the inventory through an extensive process to ensure inclusion of the best available economic, technological, and scientific data. The process began when ARB received the statewide greenhouse gas inventory from the CEC in December 2006 per Assembly Bill 1803. CEC staff had developed a comprehensive detailed inventory of statewide greenhouse gas emissions for 1990 through 2004 (CEC 2006). ARB staff devoted eight months to an extensive review of this inventory, including the data sources and methodologies used for each sector and category. The process focused on four sectors (Agriculture, Electricity Generation, Forestry and Transportation) and three categories in the Industrial sector (cement, landfills, and petroleum refining). Staff made updates and improvements to the data, methodologies, and calculations in consultation with agencies and stakeholders to ensure use of the best data and methodologies and consistency with international and national guidelines.

H. What was the public process?

The review and update process included four public workshops and nine technical discussions on the inventory. Staff held an initial workshop in late 2006, a preliminary technical discussion in early 2007, a workshop on updates in June 2007, and a workshop to discuss the draft inventory in August 2007. There have also been several technical workgroups on the emissions estimates associated with electricity generation, cement, landfills, and petroleum refining in conjunction with the development of the mandatory reporting regulation for greenhouse gases.

I. What issues were raised in the public process?

Although many topics were discussed during workshops and technical discussions, three were particularly challenging when developing the 1990 inventory: forestry, landfills, and electricity generation.

Forestry. The 1990 forestry emissions estimate uses data on greenhouse gas emissions and sinks estimated by the CEC, which are based on the results of a remote-sensing and GIS-based analysis of forest data. These data represents the best available, peer-reviewed data for the Forestry sector. During the public review of the greenhouse gas emissions data for forestry, the U.S. Department of Agriculture – Forest Service (USDA-FS) developed a draft inventory of carbon sequestration for national forests using a different methodology. The California Department of Forestry and Fire (CalFIRE) and the USDA-FS believe the CEC-based methodology used to calculate forest carbon sequestration may underestimate the amount of vegetation statewide, and therefore underestimate CO2 sinks. ARB has formed an interagency workgroup with participants from CalFIRE and USDA-FS, as well as CEC and U.S. EPA, to investigate these additional data sources and methods. The results will be incorporated in future

greenhouse gas emissions estimates and included in the Scoping Plan process as available.

Landfills. The landfill industry requested that staff alter the inventory methodology to count the carbon stored in landfills in the form of wood products and other carbon-bearing material as a sink when defining the 1990 level. Staff acknowledges that carbon is stored in landfills. However, the inventory methodology recognizes carbon sequestration at the point where carbon is removed from the atmosphere (i.e., photosynthesis in living vegetation). Counting it again when wood products are stored in landfills would constitute a double counting of sequestered CO2. Staff has proposed to calculate and track the amount of carbon stored in landfills, but not count it as a sink when calculating the 1990 emissions level.

The landfill industry and environmental organizations also recommended using different landfill gas collection efficiencies and surface cap oxidation factors than the currently used U.S. EPA default values. A wide range of estimates for these factors exist in the literature and from site-specific tests. To provide a better basis for calculating landfill emissions, staff is working with the California Integrated Waste Management Board (CIWMB) and CEC to obtain improved data on landfill gas collection efficiencies through a CEC-sponsored research study. In the meantime, the proposed inventory continues to use the U.S. EPA default values since rigorous, scientifically-based measurement data on collection efficiency and landfill cap oxidation factors are not currently available.

Electricity generation. The inventory uses the same methodology developed and used by CEC, including its fuel mix assumptions, to calculate emissions from unspecified imported power (out-of-state power from an unknown fuel type). An electric power provider recommended that the inventory use a different set of assumptions regarding the types and amount of fuel associated with unspecified imported electric power from the Pacific Northwest. ARB staff has based its final estimates for unspecified imported power in 1990 on the findings and recommendations of CEC staff. ARB staff will continue to work with the CEC and California Public Utilities Commission to obtain improved information on emissions from electricity generation for future years.

J. What documentation is available on the methods used to quantify the emissions estimates?

ARB staff has produced extensive documentation on the methods used to develop the emissions inventory for 1990, as well as for the years 1991 to 2004. Detailed calculations and methods can be found on-line at http://www.arb.ca.gov/cc/ccei/emsinv/emsinv.htm. This online documentation consists of over 12,000 pages and includes the following for every emission source estimate for years 1990 to 2004: basic calculation equations and

references to models, activity data, emission factors, GWPs, and other constants. It also includes the sources of each of these inputs.

IV. ESTIMATING THE 1990 EMISSIONS LEVEL

The amount and types of emissions in any given year are driven by California's economic and population demands. In 1990, California had over 29 million people and an economy that was one of the world's largest with a gross state product of approximately $1 trillion, equaling 13 percent of the U.S. gross domestic product (BEA 2007). As a result, transportation and electricity demand to meet California's economic and population needs were responsible for the largest quantities of greenhouse gases, with transportation accounting for over 35 percent of total emissions and electricity demands for another 26 percent. A summary of the 1990 emissions estimates for all categories in each sector is included in Table 5. A detailed summary of the 1990 inventory and the complete 1990 emissions inventory are included in Appendices A-1 and A-2, respectively.

In estimating the 1990 emissions, staff relied on a variety of information sources, most of which provide data at the state or regional level. They used emission factors primarily from the IPCC, U.S. EPA, and stakeholders. Fuel use and electricity generation data were taken from the California Energy Balance (CALEB) report, Energy Information Administration (EIA), the CEC's Quarterly Fuel and Energy Report and Petroleum Industry Information Reporting Act Data, and stakeholder input. Staff also used models where appropriate, such as EMission FACtors (EMFAC) 2007 model, which is ARB's transportation emissions model for on-road emissions, U.S. EPA models for agriculture, and the IPCC First-Order Decay model for landfills.

The 1990 emissions inventory therefore is primarily a top-down inventory since it relies on these statewide or regional data sources for its emissions estimates. For example, staff followed the top-down approach of using statewide fuel use from certain emissions sources to estimate their CO2 emissions. For the categories where data was available, staff used a bottom-up approach, relying on facility-specific data to estimate emissions. Additional information on estimation methods may be found on-line in 12,000 pages of documentation in which calculations and data sources are detailed (http://www.arb.ca.gov/cc/ccei/emsinv/emsinv.htm).

Table 5. Emissions Inventory Categories within Each Sector

Sector	Category[7,8]	1990 Emissions (MMTCO2e)[9]
Agriculture	Agricultural Energy Use	4.5
	Agricultural Residue Burning	0.1
	Agricultural Soil Management	6.7
	Enteric Fermentation	6.7
	Manure Management	5.0
	Rice Cultivation	0.4
Commercial	CHP: Commercial (UTO)	0.4
	Communication	0.1
	Domestic Utilities	0.3
	Education	1.4
	Food Services	1.9
	Health Care	1.3
	Hotels	0.7
	National Security	0.6
	Offices	1.5
	Retail & Wholesale	0.7
	Transportation Services	0.03
	Not Specified	5.6
Electricity Generation (Imports)	Specified Imports (generating plant known)	29.6
	Unspecified Imports (generating plant unknown)	31.0
	Transmission and Distribution (SF6)	1.0
Electricity Generation (In-State)	CHP: Commercial and CHP: Industrial	15.2
	Merchant Owned	2.3
	Utility Owned	29.9
	Transmission and Distribution (SF6)	1.6
Forestry	Forest and range management	0.2
Industrial	CHP: Industrial (UTO)	9.7
	Flaring	0.2
	Landfills	6.3
	Manufacturing	32.0
	Mining	0.03
	Oil & Gas Extraction	14.6
	Petroleum Marketing	0.02
	Petroleum Refining	32.8
	Pipelines	1.6
	Wastewater Treatment	3.2
	Not Specified	2.6
Residential	Household Use	29.7
Transportation	Aviation	5.1
	Water-borne (Marine Vessel)	2.2
	On road	138.0
	Rail	2.3
	Not Specified	3.0

[7] Combined Heat and Power (CHP) refers to cogeneration units supplying electric power and/or useful thermal energy. UTO is useful thermal output from CHP.
[8] Emissions in each sector not otherwise accounted for are categorized as "Not Specified".
[9] Emissions may not add up to total gross emissions in 1990 due to rounding.

A. Emissions estimates and quantification methods for key sectors and categories

The 1990 inventory emissions estimates are based on in-depth analyses of the CEC's inventory and appropriate updates by staff to include the best scientific, technological, and economic data available. The review and update process included all sectors and categories listed in Table 5. The process placed special emphasis on the sources of greenhouse gas emissions discussed below, in order of highest to lowest emissions. Emission estimates, methodologies, data sources, and updates from the CEC inventory are listed. In addition, there is a brief discussion of where inventory methods might be improved in the future as staff continues to develop annual inventories.

1. Transportation

Emissions Estimate. The Transportation sector is the largest emitter of greenhouse gases, emitting roughly 35 percent of California's greenhouse gases in 1990. It includes all on-road vehicles (passenger cars, light duty trucks, heavy duty vehicles, and motorcycles), as well as airplanes, trains, and ships. Key exclusions are interstate and international flights, as well as ships operating outside of California waters.

Transportation emitted 150.7 MMTCO2e of greenhouse gases (CO2, CH4 and N2O) in 1990. Passenger vehicles, which include passenger cars and light-duty trucks, accounted for more than 70 percent of all transportation emissions, emitting 108.5 MMTCO2e. Most of the transportation emissions were CO2. As a result, the Transportation sector was also the largest emitter of CO2 in 1990: 143.1 MMTCO2e. This estimate does not include emissions from international and interstate aviation, as well as marine fuel use outside of California waters. Since fossil fuel combustion primarily produces CO2 and relatively little CH4 and N2O, transportation accounted for a small fraction of statewide CH4 emissions, 1.0 MMTCO2e, despite the large volume of fossil fuels used in vehicles statewide. It is, however, the second largest source of N2O with 6.7 MMTCO2e, the majority of which is from on-road vehicles. Older technology catalysts, which were designed to reduce criteria pollutant emissions from on-road vehicles, produced N2O through incomplete reactions with combusted fuel.

Methodology. To quantify on-road emissions, staff used EMFAC 2007 and scaled the direct EMFAC outputs to fuel sales data for all emissions (notably CO2, carbon monoxide, total hydrocarbons, CH4, and NOx). Scaling EMFAC outputs to fuel sales enabled the transportation inventory to remain consistent with the top-down approach used for fuel combustion emissions in the rest of the inventory. Nitrous oxide for gasoline vehicles was determined from a linear regression correlating NOx with N2O based on tailpipe emissions test data. For diesel vehicles, N2O emissions were based on a per-gallon emission factor from diesel tailpipe emissions test data.

For CO2 emissions from airplanes and trains, staff followed the 2006 IPCC methodology, which multiplies the amount of fuel purchased within California by its energy content, carbon content, and a combustion efficiency assumption (IPCC/UNEP/WMO 2006). Staff used a similar approach for CH4 and N2O emissions from airplanes and trains, applying the latest U.S. EPA emission factors to available fuel data. More specific data was available for the marine vessel inventory, which staff calculated using activities and emission rate data for ship emissions that occurred in California waters (within 24 miles of California's coastline) including en transit, port, harbor, docking, and other activities. Appropriate Second Assessment Report GWPs were used in all calculations to determine final emission estimates.

Updates from CEC Inventory. Scaling EMFAC 2007 outputs to the original fuel sales data was a significant update to the previous statewide inventory compiled by CEC, resulting in a vehicle-class-specific inventory for most on-road emissions. Further updates include the recalculation of N2O emissions improvements in marine vessel estimates, which now use ARB's high resolution goods movement data to determine emissions occurring in California waters, instead of following a strictly fuel sales-based approach.

Data Sources. Staff obtained on-road gasoline, on-road diesel, and aviation gasoline fuel sale numbers from the State Board of Equalization. Fuel sales data generally correlate fairly well with fuel use. These numbers are also referenced in the Federal Highway Administration Highway Statistics annual reports and CALEB. Nearly all other fuel data (carbon content, fuel use, etc.) are from the CALEB report, which cites EIA's State Energy Consumption, Price, and Expenditure Estimates database, as well as EIA's Petroleum Marketing reports. Carbon dioxide calculation methodologies for airplanes and trains are from IPCC guidance, while on-road source emission factors come from EMFAC. For airplanes and trains, N2O and CH4 emission factors are from the U.S. EPA ship statistics and emissions currently included the inventory (fuel use as well as CO2, CH4 and N2O) are from ARB's goods movement information database.

Future Improvements to Annual Inventories. Staff is investigating the feasibility of updating EMFAC 2007 to directly calculate emission outputs for on-road vehicle N2O emissions. Staff is also considering updating airplane, train, and ship emissions based on new activity and emissions data.

2. Electricity Generation

Emissions Estimate. The Electricity Generation sector is the next largest emitter of greenhouse gases in 1990, emitting 110.6 MMTCO2e. It consists of power plants and cogenerators that generate electricity for on-site use and for sale to the power grid. Power plants typically produce electrical power to serve the grid. Cogenerators produce electricity and non-electricity useful thermal outputs, such as steam and/or hot air. The Act specifically requires that estimates shall include

greenhouse gas emissions from both in-state generated power and the generation of imported electricity delivered to and consumed in California. Emissions from transmission line losses of electricity, as well as SF6 emissions from transmission equipment, are also included.

Almost 30 percent of the electricity produced in-state in 1990 used renewable energy sources, such as biomass, solar, wind, hydropower, and geothermal (Schnapp 2007). The remainder relied on fossil fuels and nuclear power. California imported 40 percent of its electricity in 1990 to meet statewide demand. Imported electricity emitted more than 50 percent of the CO2 emissions from this sector, 60.3 MMTCO2e versus 47.3 MMTCO2e from in-state generation. Electricity generation was a relatively minor source of CH4 and N2O, emitting 0.1 MMTCO2e of CH4 and 0.4 MMTCO2e of N2O. This sector uses SF6 as an electrical insulator in the transmission and distribution of electricity. The quantities of SF6 released to the atmosphere during these applications are small, but its GWP is the highest of the greenhouse gases in the inventory. As a result, in 1990, statewide SF6 emissions from electricity generation were 2.6 MMTCO2e.

Methodology. Emissions from the Electricity Generation sector are based primarily on fuel use data obtained from the EIA. Emissions of SF6 from leaks in electrical transmission equipment are from the U.S. EPA national emissions inventory, prorated to California based on electricity generation. Staff calculated fuel combustion emissions by multiplying the heat content of fuel by its relevant emission factors and constants.

For imported power, staff used plant-specific data for known (specified) imports. The remaining unspecified imports are based on region-specific emission factors assumptions for the Pacific Northwest and Pacific Southwest regions. Staff used CEC assumptions about fuel use for both regions.

Cogeneration facilities, also known as Combined Heat and Power (CHP) plants, use some fuel for electricity generation and the rest to generate steam and other useful thermal outputs. To reflect this practice, staff only used the fraction of the fuel that each cogeneration facility reported as combusted for electricity generation to estimate electric power emissions. Emissions associated from the combustion of the remaining fuel are listed as Useful Thermal Output in the inventory and not counted under the electricity generation sector.

Updates from CEC Inventory. Significant updates from the earlier CEC inventory were the inclusion of geothermal and additional waste-to-energy data for calculating emissions from in-state power, line losses in the calculation of greenhouse gas emissions from imported power, and gross imported electricity used instead of net imports (gross imports minus exports).

Data Sources. All fuel use data is from the EIA. National SF6 emissions are from the U.S. EPA. Emission factors, fuel heat content, and GWPs are from U.S. EPA, EIA and IPCC.

Future Improvements to Annual Inventories. SF6 emissions estimates can be improved with California-specific data, which staff is currently working to obtain. Staff is also developing better methods for dividing the cogeneration emissions between respective uses. Staff is working with CEC, CPUC, and other stakeholders to improve the estimate of emissions from unspecified imports of electricity.

3. Petroleum Refining

Emissions Estimate. The petroleum refining category emitted 32.8 MMTCO2e in 1990. More than 99 percent of these emissions were CO2, including 32.6 MMTCO2e, from fuel combustion and fuels used as feedstocks. Methane and N2O emissions were relatively small, 0.2 MMTCO2e and 0.02 MMTCO2e, respectively. This category includes the 21 major refineries and minor refineries located throughout California. Major refineries (50,000+ barrels per day of crude capacity) typically receive and process petroleum crude into its component parts for sale as fuel or for use as other petroleum-based products (e.g., waxes, lubricants, etc). Minor refineries may also refine crude or work with residual oil and other heavy residuals from major refinery outputs to make asphalt or other petroleum-based products.

The primary sources of greenhouse gas emissions at refineries are emissions from cogeneration units, hydrogen production, combustion emissions associated with distillation and other refining processes, catalyst regeneration in fluidized catalytic cracking units (FCCU), and fugitive emissions.

Methodology. Staff calculated fuel combustion emissions by multiplying the heat content of fuel by its relevant emission factors and constants. Hydrogen production emissions were estimated using hydrogen generation rates. Fugitive CH4 emission estimates from refineries were derived from data in ARB's criteria pollutant database, the California Emissions Inventory Development and Reporting System (CEIDARS).

Updates from CEC Inventory. Western States Petroleum Association provided staff with improved hydrogen production data. Staff updated emission estimates from the combustion of catalyst coke and petroleum by dividing "coke" into catalyst coke and petroleum coke based on data from the CEC's Petroleum Industry Information Reporting Act (PIIRA) database. PIIRA contains data on fuel used by refineries in the State.

Data Sources. Publicly available datasets from the CEC and EIA provided improved data on fuel use. Fugitive emissions are from CEIDARS, which obtains

its data jointly from the local air districts and ARB calculations. The emission factors used in calculating emissions estimates are from U.S. EPA, EIA, and IPCC guidance.

Future Improvements to Annual Inventories. Staff is working to obtain additional data regarding the fuel used for hydrogen production. Additionally, refineries may provide data currently missing on fuel (e.g., refinery gas, naphtha, etc.) that they may export to other facilities for hydrogen production. Staff is investigating emission factor updates for CO2 from the regeneration of FCCU catalysts.

4. Agriculture

The Agriculture sector was one of the smaller greenhouse gas emitters in 1990, emitting 23.4 MMTCO2e. It includes agricultural energy use, agricultural soil management, agricultural residue burning, enteric fermentation, manure management, and rice cultivation. The sector emits a relatively small amount of CO2 emissions compared to other sectors. The largest CO2 emission source is fuel combustion in agricultural equipment (4.5 MMTCO2e). This sector, however, includes the largest emitter of CH4, enteric fermentation (animal digestion) which emits 6.7 MMTCO2e of CH4 in 1990. Agricultural energy use, agricultural residue burning, manure management, and rice cultivation emitted an additional 4.9 MMTCO2e of CH4. Agriculture was also the largest source of N2O in California in 1990. Agricultural soil management (processes that increase soil nitrogen availability) was responsible for 88 percent of N2O emissions within the agriculture sector and 40 percent of all N2O emissions statewide. Discussion of methodologies, data sources, and future improvements for this sector will focus on agricultural soil management, enteric fermentation, and manure management since they are the highest emitting categories in this sector.

Agricultural Soil Management

Emissions Estimate. Agricultural soil management was the highest emitter of N2O in 1990, emitting 6.6 MMTCO2e of N2O and 0.1MMTCO2e of CO2. This category consists of agricultural activities that increase soil nitrogen availability including: applying fertilizers and manure; growing nitrogen fixing crops; retaining crop residuals; liming of soils; depositing waste by domestic and grazing animals; and, cultivating histosols (soils with high organic matter content). Emissions of N2O from managed soils occur as a result of nitrification and denitrification in soil.

Methodology. Staff calculated N2O emissions using an emission factor model, which is based on the 2006 IPCC guidelines and the guidance from the U.S. EPA's Emissions Inventory Improvement Program for greenhouse gases. Staff adapted the parameter values used by CEC staff to make them California-specific. For example, the residue-to-crop mass ratio and the fraction of residue applied were adjusted down for some crops to match the estimated residue

tonnages for agricultural burning in California. Staff multiplied applied tons of limestone and dolomite by the dolomite and limestone emission factors to estimate CO2 emissions since CO2 is emitted to the atmosphere when the limestone and dolomite applied to agricultural soils degrades.

Updates from CEC Inventory. Improvements for estimating N2O emissions from agricultural soil management included computational improvements and updated emission factors.

Data Sources. Activity data are from CEC emission inventory spreadsheets, which are primarily from the California Department of Food and Agriculture (CDFA). Fertilizer usage data is from *Fertilizing Materials Tonnage Reports*, published by CDFA. Crop production data is from USDA National Agriculture Statistics Services. The animal population data used to estimate manure production were from the national greenhouse gas inventory spreadsheets (U.S. EPA 2007). Staff estimated histosols cultivation acreage based on the expert judgment of two California State soil scientists (CEC 2006). The amounts of limestone and dolomite applied to cropland soils are from the CDFA annual fertilizing materials tonnage reports and annual editions of the U.S. Geological Survey (USGS) *Minerals Yearbook*.

Future Improvements to Annual Inventories. Staff will evaluate the feasibility of using process-based models to quantify N2O emissions. Emission factor models cannot capture the emission variations from a wide range of agro-ecosystems, since N2O emissions from nitrification and denitrification processes are driven by many factors, such as climate, soil, and agricultural practices.

Enteric Fermentation

Emissions Estimate. Enteric fermentation is the microbial fermentation process in an animal's digestive system that produces CH4, which is in turn exhaled or burped by the animal. This process is the largest statewide emitter of CH4 in 1990, emitting 6.7 MMTCO2e of CH4, most of which was released by domesticated ruminant animals.

Methodology. Staff used the U.S. EPA enteric fermentation emissions methodology to calculate California-specific emissions, consistent with 2006 IPCC guidance. The majority of enteric fermentation emissions are from dairy and beef cattle. Staff used a more detailed methodology to estimate emissions for domesticated cattle (except bulls) that employs several models and calculations. A less detailed methodology provided emissions estimates for other livestock, because overall these animals contribute a relatively small amount of the total enteric fermentation CH4 emissions.

Updates from CEC Inventory. Updates from the CEC inventory estimates of enteric fermentation emissions centered on improved emission factors and data inputs obtained from U.S. EPA.

Data Sources. The original source of the animal population data, except for horses, is from the U.S. Department of Agricultural (USDA) National Agricultural Statistics Service (NASS). Horse population data is from the Food and Agriculture Organization (FAO). Output from the University of California, Davis AAMOLLEY model provides cattle digestible energy and CH4 conversion rates by population category. Staff calculated the gross energy factor using IPCC recommended methods. For "other livestock" animal types, such as sheep and swine, staff obtained the emission factors from the 2006 IPCC guidance.

Future Improvements to Annual Inventories. Staff is investigating potential improvements to the enteric fermentation methodology. As research results emerge, and as the IPCC and U.S. EPA improve methodologies, the inventory will be updated to reflect those improvements.

Manure Management

Emissions Estimate. The manure management category emitted 5.0 MMTCO2e in 1990, the majority of which was CH4 emissions. This sector includes the storage of livestock or poultry manure in liquid systems. The storage or treatment of manure waste in anaerobic conditions, such as liquid slurry in a pond or lagoon, promotes anaerobic decomposition of organic material, which produces CH4 emissions. Small amounts of N2O are also produced through nitrification and denitrification.

When manure is handled as a solid, it tends to decompose aerobically, primarily producing N2O and little or no CH4. Nitrous oxide emissions from manure managed in pasture, range, and paddock or as daily spread is included in the agricultural soil management category.

Methodology. Staff used the U.S. EPA emissions calculation methodology for manure management to calculate California-specific emissions. The methodology considers animal population and location, amount of dry versus liquid manure, CH4 and N2O emission factors, and other inputs. It is consistent with 2006 IPCC guidance and recommendations.

Updates from CEC Inventory. Updates from the earlier CEC inventory estimates emissions from manure management centered on improved emission factors and data inputs obtained from U.S. EPA.

Data Sources. Animal population data, except for horses, is from the USDA NASS. Horse population data is from the FAO. Staff obtained all factors used to

estimate CH4 and N2O emissions from U.S EPA's inventory spreadsheets and reports.

Future Improvements to Annual Inventories. As research results emerge, and as the IPCC and U.S. EPA improve methodologies, staff will update future time series inventories.

5. Landfills

Emissions Estimate. Landfills are the second highest emitter of CH4 statewide, releasing 6.3 MMTCO2e as a result of the degradation of organic waste. Anaerobic decomposition of landfilled waste forms roughly an even mix of CO2 and CH4 as a byproduct of degradation. Methane emissions from landfills are the chief pollutant of concern for this category. The CO2 generated from landfills, whether through oxidation in cover material or through landfill gas combustion, is considered biogenic and accounted for in the atmospheric CO2 flux (see Appendix B).

The landfills included in the inventory are only those landfills in California that receive or have received organic waste. Landfills receiving only ash or inert construction debris are not considered since they do not emit CH4. A large fraction of landfill carbon, including organic waste, cannot degrade and may be permanently sequestered in the landfill.

Landfills may install or expand a gas collection system to capture landfill gases in an effort to comply with local, state or federal regulations. Captured gas may be flared, filtered, or combusted for electricity production. Some landfills do not generate enough gas for effective combustion and simply vent the gas. Gases that are not captured escape through the surface or migrate out through other means.

Methodology. Staff used the IPCC Mathematically Exact First-Order Decay Model, which calculates the amount of carbon that degrades over time in a landfill. The amount of landfill carbon before degradation is based on national and California waste characterization studies and 2006 IPCC factors that convert each waste type into carbon mass. Staff received the total amount of waste deposited into landfills (waste-in-place data) from CIWMB for 1990 and prior years. All of these data served as inputs into the IPCC model.

Staff surveyed landfills in the State to improve the model output results, augmenting model estimates with actual measured landfill gas collection levels. Collection efficiencies and oxidation factors for gas migration through the cover soils used defaults of 75 percent and 10 percent, respectively. Staff combined these defaults with the model output to determine total amount of CH4 that was released.

Updates from CEC Inventory. CEC relied on CEIDARS data for landfill CH4, which is based on local air district-specific methods. Staff updated emissions estimates by using waste data obtained from CIWMB in conjunction with IPCC models to obtain a consistent, statewide estimate that incorporates all the latest data available.

Data Sources. Waste-in-place data is from the CIWMB. Rainfall for each landfill, which influenced landfill decay rates, is based on data from CIWMB and the Natural Resources Conservation Service. The decay model itself is from the 2006 IPCC Guidelines (Mathematically Exact First-Order Decay Model). Waste characterization comes from U.S. EPA (national data) and CIWMB (California-specific data) studies, while carbon content and sequestration factors come from U.S. EPA, CEC, and 2006 IPCC Guidelines. The default collection efficiency of 75 percent is from U.S. EPA. The default oxidation factor of 10 percent for gas migration through the surface cap is from 2006 IPCC Guidance.

Future Improvements to Annual Inventories. Staff is currently working to obtain more landfill-specific survey data to better improve estimates. Staff hopes to improve the default collection and oxidation values through studies focused on these areas.

6. Cement

Emissions Estimate. The cement category includes all cement manufacturers in California. Emissions result from the processing of raw materials into clinker, as well as the combustion of fuel to heat kilns. Clinker is one of the key ingredients used to produce cement, releasing CO2 in the process. The production of clinker produced 4.6 MMTCO2e in 1990. Carbon dioxide was also emitted, along with small quantities of CH4 and N2O, when fossil fuel was combusted to heat kilns, emitting 3.5 MMTCO2e. Carbon dioxide emissions from clinker production accounted for unrecycled cement kiln dust (CKD).

Methodology. Staff calculated CO2 emissions from clinker production by first multiplying clinker production data with a clinker CO2 emission factor, and then by a CKD correction factor. The CKD correction factor is calculated based on the known amounts of CKD leaving the kiln, the bypass dust leaving the kiln, and a CKD factor (IPCC/UNEP/WMO 2006). Staff calculated fuel combustion emissions by multiplying the heat content of fuel by its relevant emission factors and constants.

Updates from CEC Inventory. Staff used known amounts of clinker production, cement kiln and bypass dust data, and fuel use data, which are all based on facility-specific surveys aggregated to a statewide total. CEC used a default correction factor for CKD, because data on the amounts of CKD were not available. CEC also used clinker production data from the USGS, whereas ARB

staff used plant-specific aggregated clinker production data provided by the Portland Cement Association (PCA).

Data Sources. PCA provided California-specific data on clinker production, cement kiln dust, bypass dust leaving the kiln system, and fuel use from a cement plant survey for 1990, 1995, 2000, and 2005. ARB staff interpolated missing data for the intervening years, upon PCA's recommendation. The clinker emission factor and the factor for cement kiln dust are IPCC factors (IPCC/UNEP/WMO 2006).

Future Improvements to Annual Inventories. ARB staff would like to obtain cement plant-specific data on the mass of individual inputs (i.e., carbonates) consumed in the kiln to produce clinker. These data would be used to improve the CO2 emissions resulting from clinker production in future time series inventories.

7. Forestry and Rangelands

Emissions Estimate. The Forestry sector is unique, because it not only includes CO2, CH4, and N2O emissions from disturbances on forests and rangelands, such as harvest, fire, and land use conversion, but also includes removals of atmospheric CO2 by photosynthesis, which is then bound (sequestered) in plant tissues. The inventory balances the CO2 emissions and atmospheric removals of CO2 by vegetation through an atmospheric CO2 flux approach (Appendix B). The sector's emissions are therefore the sum total of greenhouse gas emissions to the atmosphere and CO2 removals by photosynthesis.

In 1990, this sector removed more CO2 from the atmosphere than it emitted. As a result, it was a net sink, removing 6.7 MMTCO2e from the atmosphere in 1990. Emissions from the Forestry sector due to management of forests and rangelands accounted for less than one percent of all CH4 and N2O emissions statewide in 1990.

Methodology. For forests and rangelands, staff estimated CO2 removals and emissions from changes in forest and rangeland biomass with products developed by Winrock for CEC (CEC 2004). The products used satellite imagery and empirical relationships between tree canopy cover and biomass to estimate changes in biomass over time. Increases in biomass are associated with removals of CO2 from the atmosphere, while decreases indicate wood harvesting and emissions from fires (CO2, CH4, and N2O) and harvest events (CO2 and CH4). Winrock provided data for 1994-2000. Staff used scaling factors based on forest land area trends from CalFIRE and USDA-FS to extrapolate data for the remaining years (1990-1993 and 2001-2004). Emissions associated with soil disturbance and residue oxidation resulting from harvest activities are accounted for in the inventory. When wood is harvested, a portion of the tree biomass is converted to wood products. The wood products serve as

reserves of carbon, some of which degrade slowly over long periods of time to CO2 and CH4 in landfills and composts. Staff estimated emissions from the statewide disposal of wood products as part of the landfill category.

Updates from CEC Inventory. Forest and rangeland greenhouse emissions are reported by individual gas (CO2, CH4, and N2O) and emission source (e.g., fire, soil disturbances, etc.). CEC combined these gases and sources. The Forestry sector inventory now includes emissions from the decomposition of wood products disposed in landfills, and emissions from composting operations. Emissions from landfilled and composted urban greenwaste are now reported under the landfills category, pending further data on atmospheric CO2 removals by urban forests. Woody and non-woody crop biomass annual stock changes have been removed from the inventory pending further study.

Data Sources. Staff used products developed by Winrock for the CEC PIER program to estimate CO2 removals and greenhouse gas emissions for forests and rangelands. Data on wood product use in the State is from WOODCARB model output provided by the USDA-FS Forest Products Laboratory. CIWMB provided data on wood product disposal in landfills. The decay rates used to model CO2 and CH4 generation from landfilled wood product decomposition are from the U.S. EPA.

Future Improvements to Annual Inventories. ARB is partnering with land management agencies and the research community to investigate the feasibility of using products from the USDA-FS Forest Inventory and Analysis (FIA) program to better estimate biomass and carbon stocks and stock changes on forested lands. The FIA represents a robust standard for forest inventories, and serves as the basis for the U.S. EPA forest lands greenhouse gas inventory.

Trees in urban areas account for a small but increasing fraction of forest cover in the State. Future inventories may include an inventory of urban forest stocks and stock changes. Future editions of the inventory could also include soil organic carbon, which makes up a large carbon reservoir on forested lands, rangelands and croplands, as data and models become available.

Improvements to forecasting for this sector beyond land area trends will involve assessments of climate forcing and future human activities affecting biomass stocks, such as forest management. These assessments will also be needed to develop forecasts for other categories of managed land, such as croplands and urban areas.

B. Emissions estimates for other sectors

The remaining statewide greenhouse gas emissions in 1990 were from sectors and categories not discussed above, but included in Table 5. Staff reviewed the CEC estimates for these emissions sources and, as appropriate, updated the

input data, emission factors, and methodologies to reflect the best available data and estimation methods. Commercial and Residential sectors are discussed briefly below since they are not part of the four sectors examined above. The Industrial sector is also mentioned since it is much broader than the three industrial categories (landfills, cement, and petroleum refining) discussed previously.

The Commercial sector emitted 14.4 MMTCO2e, while the Residential sector emitted 29.7 MMTCO2e in 1990. The Commercial sector includes emissions from all commercial activities statewide, as listed in Table 5. The Residential sector contains emissions from households. Staff combined fuel use data and improved emission factors from the IPCC to calculate emissions in both sectors. This approach is the same as that used by the CEC.

Greenhouse gas emissions for both sectors were due to fuel combustion. Fuel was burned to prepare food, heat buildings, provide hot water and steam, and supply energy for natural gas transmission through pipelines. As a result, the Commercial sector emitted 14.4 MMTCO2e of CO2 and 0.06 MMTCO2e of CH4 in 1990. The Residential sector produced 29.1 MMTCO2e of CO2 and 0.5 MMTCO2e of CH4. Both sectors emitted very little N2O as a by-product of fuel combustion.

The Industrial sector, which includes cement production, landfills and petroleum refining, emitted a substantial amount of greenhouse gases in 1990, 103.0 MMTCO2e. More than 70 percent of these emissions are due to fuel combustion.

V. PRELIMINARY 2020 GREENHOUSE GAS PROJECTIONS

As ARB develops the Scoping Plan, which identifies actions for reducing greenhouse gases to the 1990 level, it will be necessary to estimate a projected 2020 business-as-usual statewide emissions estimate of total greenhouse gases. Business-as-usual emissions estimates are the levels anticipated to occur in the absence of additional policies and measures aimed at reducing future emissions. Projections are based on forecasted demographic and economic growth.

A 2020 business-as-usual forecast will be included in the 2008 Scoping Plan. For Scoping Plan development, staff has calculated a preliminary net business-as-usual emissions estimate for 2020, which is approximately 600 MMTCO2e. The difference between the proposed 1990 emissions level and ARB's preliminary estimate of 2020 emissions is therefore 173 MMTCO2e. This number will be refined in the final Scoping Plan.

VI. CONCLUSIONS

Staff estimates that the 1990 statewide emissions level was 427 MMTCO2e. Staff proposes that the Board approve 427 MMTCO2e as California's greenhouse gas emissions limit for 2020.

The total reductions needed to achieve a level of 427 MMTCO2e by 2020 are determined from the difference between the projected 2020 business-as-usual emissions level and the proposed 2020 limit of 427 MMTCO2e. Staff developed a preliminary estimate of approximately 600 MMTCO2e for the 2020 business-as-usual projection. This 2020 business-as-usual estimate will continue to be assessed during development of the Scoping Plan in 2008.

Staff will continue to work to improve our greenhouse gas inventory methods and data as we develop annual greenhouse gas inventories. If additional information becomes available that would significantly alter the total emissions for 1990, staff will bring a revised 1990 emissions level back to the Board for consideration.

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Appendix A-1

1990 GHG Inventory by IPCC Summary Categories

California Greenhouse Gas Inventory for 1990 (millions of tonnes of CO2 equivalent)

(CO2 equivalence based upon IPCC Second Assessement Report's Global Warming Potentials)

Categories Included in the Inventory.	
1 - Energy	**386.41**
1A - Fuel Combustion Activities	***381.16***
1A1 - Energy Industries	**157.33**
1A1a - Main Activity Electricity and Heat Production	115.84
1A1ai - Electricity Generation	90.502
1A1aii - Combined Heat and Power Generation (CHP)	25.341
1A1b - Petroleum Refining	27.63
1A1c - Manufacture of Solid Fuels and Other Energy Industries	13.86
1A1cii - Other Energy Industries	13.858
1A2 - Manufacturing Industries and Construction	**24.24**
1A2c - Chemicals	0.96
1A2d - Pulp, Paper and Print	1.91
1A2e - Food Processing, Beverages and Tobacco	3.07
1A2f - Non-Metallic Minerals	5.12
1A2g - Transport Equipment	0.53
1A2h - Machinery	1.33
1A2i - Mining (excluding fuels) and Quarrying	0.03
1A2j - Wood and Wood Products	0.24
1A2k - Construction	0.67
1A2l - Textile and Leather	0.38
1A2m - Non-specified Industry.	9.04
1A3 - Transport	**150.02**
1A3a - Civil Aviation	5.13
1A3aii - Domestic Aviation	5.113
1A3b - Road Transportation	137.99
1A3bi - Cars	63.746
1A3bii - Light-duty Trucks	44.754
1A3biii - Heavy-duty Trucks and Buses	29.031
1A3biv - Motorcycles	0.426
1A3c - Railways	2.33
1A3d - Water-borne Navigation	2.21
1A3di - International Water-borne Navigation (International Bunkers)	0.548
1A3dii - Domestic Water-borne Navigation	1.662
1A4 - Other Sectors	**48.19**
1A4a - Commercial/Institutional	14.03
1A4b - Residential	29.66
1A4c - Agriculture/Forestry/Fishing/Fish Farms	4.50
1A5 - Non-Specified	**1.38**
1B - Fugitive Emissions from Fuels	***5.25***
1B2 - Oil and Natural Gas	**2.94**
1B2a - Oil	0.14
1B2aiii - All Other	0.139
1B2b - Natural Gas	1.50
1B3 - Other Emissions from Energy Production	**2.31**

California Greenhouse Gas Inventory for 1990 (millions of tonnes of CO2 equivalent)

(CO2 equivalence based upon IPCC Second Assessement Report's Global Warming Potentials)

Categories Included in the Inventory.	
2 - Industrial Processes and Product Use	**18.34**
2A - Mineral Industry	***4.85***
2A1 - Cement Production	**4.62**
2A2 - Lime Production	**0.23**
2B - Chemical Industry	***2.34***
2B2 - Nitric Acid Production	**0.53**
2D - Non-Energy Products from Fuels and Solvent Use	***2.29***
2D1 - Lubricant Use	**1.13**
2D2 - Paraffin Wax Use	**0.00**
2D4 - Other (please specify)	**1.16**
2E - Electronics Industry	***0.59***
2F - Product Uses as Substitutes for Ozone Depleting Substances	***0.04***
2G - Other Product Manufacture and Use	***3.18***
2G1 - Electrical Equipment	**2.58**
2G1b - Use of Electrical Equipment	2.58
2G4 - Other (Please specify)	**0.61**
2H - Other	***5.05***
2H3 - Other (please specify)	**5.05**
3 - Agriculture, Forestry and Other Land Use	**19.11**
3A - Livestock	***11.67***
3A1 - Enteric Fermentation	**6.67**
3A1a - Cattle	6.25
3A1ai - Dairy Cows	3.632
3A1aii - Other Cattle	2.618
3A1c - Sheep	0.17
3A1d - Goats	0.00
3A1f - Horses	0.24
3A1h - Swine	0.01
3A2 - Manure Management	**5.00**
3A2a - Cattle	4.68
3A2ai - Dairy Cows	4.359
3A2aii - Other Cattle	0.324
3A2c - Sheep	0.02
3A2d - Goats	0.00
3A2f - Horses	0.03
3A2h - Swine	0.07
3A2i - Poultry	0.20
3B - Land	***0.19***
3B1 - Forest Land	**0.19**

California Greenhouse Gas Inventory for 1990 (millions of tonnes of CO2 equivalent)

(CO2 equivalence based upon IPCC Second Assessement Report's Global Warming Potentials)

Categories Included in the Inventory.	
3C - Aggregate Sources and Non-CO2 Emissions Sources on Land	7.26
3C1 - Emissions from Biomass Burning	0.12
3C1b - Biomass Burning in Croplands	0.12
3C2 - Liming	0.07
3C4 - Direct N2O Emissions from Managed Soils	5.20
3C5 - Indirect N2O Emissions from Managed Soils	1.44
3C7 - Rice Cultivations	0.41
4 - Waste	9.42
4A - Solid Waste Disposal	6.26
4A1 - Managed Waste Disposal Sites	6.26
4D - Wastewater Treatment and Discharge	3.17
4D1 - Domestic Wastewater Treatment and Discharge	2.83
4D2 - Industrial Wastewater Treatment and Discharge	0.34

Summary of Categories Included in the Inventory.	
Gross California Emissions	433.29
Sinks and Sequestrations from Rangelands and Forestry	-6.69
Net California Emissions	426.60

Categories Excluded from the Inventory.	
1 - Energy	59.02
1A - Fuel Combustion Activities	59.02
1A3 - Transport	59.02
1A3a - Civil Aviation	33.95
1A3ai - International Aviation (International Bunkers)	14.597
1A3aii - Domestic Aviation	19.357
1A3d - Water-borne Navigation	25.06
1A3di - International Water-borne Navigation (International Bunkers)	25.062

Summary of Categories Excluded from the Inventory.	
Gross California Emissions	59.02
Net California Emissions	59.02

Appendix A-2

1990 GHG Inventory by IPCC Category (Full Detail)

California Greenhouse Gas Inventory for 1990 (millions of tonnes of CO2 equivalent)

(CO2 equivalence based upon IPCC Second Assessement Report's Global Warming Potentials)

Categories Included in the Inventory.

1 - Energy	**386.41**
1A - Fuel Combustion Activities	***381.16***
1A1 - Energy Industries	**157.33**
1A1a - Main Activity Electricity and Heat Production	115.84
1A1ai - Electricity Generation	*90.502*
Imported Electricity : Specified Imports : PNW : Boardman (OR) - Coal > CH4	0.000
Imported Electricity : Specified Imports : PNW : Boardman (OR) - Coal > CO2	0.281
Imported Electricity : Specified Imports : PNW : Boardman (OR) - Coal > N2O	0.001
Imported Electricity : Specified Imports : PNW : Boardman (OR) - Distillate > CH4	0.000
Imported Electricity : Specified Imports : PNW : Boardman (OR) - Distillate > CO2	0.001
Imported Electricity : Specified Imports : PNW : Boardman (OR) - Distillate > N2O	0.000
Imported Electricity : Specified Imports : PNW : Colstrip (MT) - Coal > CH4	0.000
Imported Electricity : Specified Imports : PNW : Colstrip (MT) - Coal > CO2	0.921
Imported Electricity : Specified Imports : PNW : Colstrip (MT) - Coal > N2O	0.004
Imported Electricity : Specified Imports : PNW : Colstrip (MT) - Distillate > CH4	0.000
Imported Electricity : Specified Imports : PNW : Colstrip (MT) - Distillate > CO2	0.001
Imported Electricity : Specified Imports : PNW : Colstrip (MT) - Distillate > N2O	0.000
Imported Electricity : Specified Imports : PSW : Bonanza (UT) - Coal > CH4	0.000
Imported Electricity : Specified Imports : PSW : Bonanza (UT) - Coal > CO2	0.620
Imported Electricity : Specified Imports : PSW : Bonanza (UT) - Coal > N2O	0.003
Imported Electricity : Specified Imports : PSW : Bonanza (UT) - Distillate > CH4	0.000
Imported Electricity : Specified Imports : PSW : Bonanza (UT) - Distillate > CO2	0.000
Imported Electricity : Specified Imports : PSW : Bonanza (UT) - Distillate > N2O	0.000
Imported Electricity : Specified Imports : PSW : Four Corners (NM) - Coal > CH4	0.001
Imported Electricity : Specified Imports : PSW : Four Corners (NM) - Coal > CO2	5.007
Imported Electricity : Specified Imports : PSW : Four Corners (NM) - Coal > N2O	0.024
Imported Electricity : Specified Imports : PSW : Four Corners (NM) - Natural Gas > CH4	0.000
Imported Electricity : Specified Imports : PSW : Four Corners (NM) - Natural Gas > CO2	0.014
Imported Electricity : Specified Imports : PSW : Four Corners (NM) - Natural Gas > N2O	0.000
Imported Electricity : Specified Imports : PSW : Intermountain (UT) - Coal > CH4	0.002
Imported Electricity : Specified Imports : PSW : Intermountain (UT) - Coal > CO2	11.102
Imported Electricity : Specified Imports : PSW : Intermountain (UT) - Coal > N2O	0.055
Imported Electricity : Specified Imports : PSW : Intermountain (UT) - Distillate > CH4	0.000
Imported Electricity : Specified Imports : PSW : Intermountain (UT) - Distillate > CO2	0.016
Imported Electricity : Specified Imports : PSW : Intermountain (UT) - Distillate > N2O	0.000
Imported Electricity : Specified Imports : PSW : Mohave (NV) - Coal > CH4	0.001
Imported Electricity : Specified Imports : PSW : Mohave (NV) - Coal > CO2	6.595
Imported Electricity : Specified Imports : PSW : Mohave (NV) - Coal > N2O	0.033
Imported Electricity : Specified Imports : PSW : Mohave (NV) - Natural Gas > CH4	0.000
Imported Electricity : Specified Imports : PSW : Mohave (NV) - Natural Gas > CO2	0.084
Imported Electricity : Specified Imports : PSW : Mohave (NV) - Natural Gas > N2O	0.000
Imported Electricity : Specified Imports : PSW : Navajo (AZ) - Coal > CH4	0.001
Imported Electricity : Specified Imports : PSW : Navajo (AZ) - Coal > CO2	3.233
Imported Electricity : Specified Imports : PSW : Navajo (AZ) - Coal > N2O	0.016
Imported Electricity : Specified Imports : PSW : Navajo (AZ) - Distillate > CH4	0.000
Imported Electricity : Specified Imports : PSW : Navajo (AZ) - Distillate > CO2	0.006
Imported Electricity : Specified Imports : PSW : Navajo (AZ) - Distillate > N2O	0.000
Imported Electricity : Specified Imports : PSW : Reid Gardner (NV) - Coal > CH4	0.000
Imported Electricity : Specified Imports : PSW : Reid Gardner (NV) - Coal > CO2	1.110
Imported Electricity : Specified Imports : PSW : Reid Gardner (NV) - Coal > N2O	0.006
Imported Electricity : Specified Imports : PSW : Reid Gardner (NV) - Distillate > CH4	0.000
Imported Electricity : Specified Imports : PSW : Reid Gardner (NV) - Distillate > CO2	0.001
Imported Electricity : Specified Imports : PSW : Reid Gardner (NV) - Distillate > N2O	0.000

Categories Included in the Inventory.

Imported Electricity : Specified Imports : PSW : San Juan (NM) - Coal > CH4	0.000
Imported Electricity : Specified Imports : PSW : San Juan (NM) - Coal > CO2	0.405
Imported Electricity : Specified Imports : PSW : San Juan (NM) - Coal > N2O	0.002
Imported Electricity : Specified Imports : PSW : San Juan (NM) - Distillate > CH4	0.000
Imported Electricity : Specified Imports : PSW : San Juan (NM) - Distillate > CO2	0.001
Imported Electricity : Specified Imports : PSW : San Juan (NM) - Distillate > N2O	0.000
Imported Electricity : Specified Imports : PSW : San Juan (NM) - Residual Fuel Oil > CH4	0.000
Imported Electricity : Specified Imports : PSW : San Juan (NM) - Residual Fuel Oil > CO2	0.001
Imported Electricity : Specified Imports : PSW : San Juan (NM) - Residual Fuel Oil > N2O	0.000
Imported Electricity : Specified Imports : PSW : Yucca/Yuma Axis (AZ) - Distillate > CH4	0.000
Imported Electricity : Specified Imports : PSW : Yucca/Yuma Axis (AZ) - Distillate > CO2	0.001
Imported Electricity : Specified Imports : PSW : Yucca/Yuma Axis (AZ) - Distillate > N2O	0.000
Imported Electricity : Specified Imports : PSW : Yucca/Yuma Axis (AZ) - Natural Gas > CH4	0.000
Imported Electricity : Specified Imports : PSW : Yucca/Yuma Axis (AZ) - Natural Gas > CO2	0.054
Imported Electricity : Specified Imports : PSW : Yucca/Yuma Axis (AZ) - Natural Gas > N2O	0.000
Imported Electricity : Specified Imports : PSW : Yucca/Yuma Axis (AZ) - Residual Fuel Oil > CH4	0.000
Imported Electricity : Specified Imports : PSW : Yucca/Yuma Axis (AZ) - Residual Fuel Oil > CO2	0.000
Imported Electricity : Specified Imports : PSW : Yucca/Yuma Axis (AZ) - Residual Fuel Oil > N2O	0.000
Imported Electricity : Unspecified Imports : PNW - Imported electricity > CH4	0.002
Imported Electricity : Unspecified Imports : PNW - Imported electricity > CO2	7.828
Imported Electricity : Unspecified Imports : PNW - Imported electricity > N2O	0.038
Imported Electricity : Unspecified Imports : PSW - Imported electricity > CH4	0.005
Imported Electricity : Unspecified Imports : PSW - Imported electricity > CO2	22.972
Imported Electricity : Unspecified Imports : PSW - Imported electricity > N2O	0.112
In State Generation : Merchant Owned - Biomass > CH4	0.030
In State Generation : Merchant Owned - Biomass > N2O	0.059
In State Generation : Merchant Owned - Digester Gas > CH4	0.000
In State Generation : Merchant Owned - Digester Gas > N2O	0.000
In State Generation : Merchant Owned - Distillate > CH4	0.000
In State Generation : Merchant Owned - Distillate > CO2	0.026
In State Generation : Merchant Owned - Distillate > N2O	0.000
In State Generation : Merchant Owned - Jet Fuel > CH4	0.000
In State Generation : Merchant Owned - Jet Fuel > CO2	0.000
In State Generation : Merchant Owned - Jet Fuel > N2O	0.000
In State Generation : Merchant Owned - Kerosene > CH4	0.000
In State Generation : Merchant Owned - Kerosene > CO2	0.000
In State Generation : Merchant Owned - Kerosene > N2O	0.000
In State Generation : Merchant Owned - Landfill Gas > CH4	0.000
In State Generation : Merchant Owned - Landfill Gas > N2O	0.000
In State Generation : Merchant Owned - MSW > CH4	0.006
In State Generation : Merchant Owned - MSW > CO2	0.277
In State Generation : Merchant Owned - MSW > N2O	0.011
In State Generation : Merchant Owned - Natural Gas > CH4	0.000
In State Generation : Merchant Owned - Natural Gas > CO2	0.356
In State Generation : Merchant Owned - Natural Gas > N2O	0.000
In State Generation : Merchant Owned - Other Coal > CH4	0.000
In State Generation : Merchant Owned - Other Coal > CO2	0.112
In State Generation : Merchant Owned - Other Coal > N2O	0.001
In State Generation : Merchant Owned - Petroleum Coke > CH4	0.000
In State Generation : Merchant Owned - Petroleum Coke > CO2	0.481
In State Generation : Merchant Owned - Petroleum Coke > N2O	0.001
In State Generation : Merchant Owned - Propane > CH4	0.000
In State Generation : Merchant Owned - Propane > CO2	0.000
In State Generation : Merchant Owned - Propane > N2O	0.000
In State Generation : Merchant Owned - Refinery Gas > CH4	0.000

Categories Included in the Inventory.

In State Generation : Merchant Owned - Refinery Gas > CO2	0.000
In State Generation : Merchant Owned - Refinery Gas > N2O	0.000
In State Generation : Merchant Owned - Residual Fuel Oil > CH4	0.000
In State Generation : Merchant Owned - Residual Fuel Oil > CO2	0.000
In State Generation : Merchant Owned - Residual Fuel Oil > N2O	0.000
In State Generation : Merchant Owned - Waste Oil > CH4	0.000
In State Generation : Merchant Owned - Waste Oil > CO2	0.000
In State Generation : Merchant Owned - Waste Oil > N2O	0.000
In State Generation : Utility Owned - Biomass > CH4	0.000
In State Generation : Utility Owned - Biomass > N2O	0.000
In State Generation : Utility Owned - Digester Gas > CH4	0.000
In State Generation : Utility Owned - Digester Gas > N2O	0.000
In State Generation : Utility Owned - Distillate > CH4	0.000
In State Generation : Utility Owned - Distillate > CO2	0.080
In State Generation : Utility Owned - Distillate > N2O	0.000
In State Generation : Utility Owned - Landfill Gas > CH4	0.000
In State Generation : Utility Owned - Landfill Gas > N2O	0.000
In State Generation : Utility Owned - Natural Gas > CH4	0.010
In State Generation : Utility Owned - Natural Gas > CO2	24.992
In State Generation : Utility Owned - Natural Gas > N2O	0.015
In State Generation : Utility Owned - Residual Fuel Oil > CH4	0.003
In State Generation : Utility Owned - Residual Fuel Oil > CO2	3.471
In State Generation : Utility Owned - Residual Fuel Oil > N2O	0.008
1A1aii - Combined Heat and Power Generation (CHP)	*25.341*
CHP: Commercial : Useful Thermal Output - Biomass > CH4	0.000
CHP: Commercial : Useful Thermal Output - Biomass > N2O	0.000
CHP: Commercial : Useful Thermal Output - Digester Gas > CH4	0.000
CHP: Commercial : Useful Thermal Output - Digester Gas > N2O	0.000
CHP: Commercial : Useful Thermal Output - Distillate > CH4	0.000
CHP: Commercial : Useful Thermal Output - Distillate > CO2	0.004
CHP: Commercial : Useful Thermal Output - Distillate > N2O	0.000
CHP: Commercial : Useful Thermal Output - Jet Fuel > CH4	0.000
CHP: Commercial : Useful Thermal Output - Jet Fuel > CO2	0.000
CHP: Commercial : Useful Thermal Output - Jet Fuel > N2O	0.000
CHP: Commercial : Useful Thermal Output - Landfill Gas > CH4	0.000
CHP: Commercial : Useful Thermal Output - Landfill Gas > N2O	0.000
CHP: Commercial : Useful Thermal Output - Natural Gas > CH4	0.000
CHP: Commercial : Useful Thermal Output - Natural Gas > CO2	0.386
CHP: Commercial : Useful Thermal Output - Natural Gas > N2O	0.000
CHP: Commercial : Useful Thermal Output - Propane > CH4	0.000
CHP: Commercial : Useful Thermal Output - Propane > CO2	0.000
CHP: Commercial : Useful Thermal Output - Propane > N2O	0.000
CHP: Commercial : Useful Thermal Output - Refinery Gas > CH4	0.000
CHP: Commercial : Useful Thermal Output - Refinery Gas > CO2	0.009
CHP: Commercial : Useful Thermal Output - Refinery Gas > N2O	0.000
CHP: Commercial : Useful Thermal Output - Waste Oil > CH4	0.000
CHP: Commercial : Useful Thermal Output - Waste Oil > CO2	0.000
CHP: Commercial : Useful Thermal Output - Waste Oil > N2O	0.000
CHP: Industrial : Useful Thermal Output - Associated gas > CH4	0.000
CHP: Industrial : Useful Thermal Output - Associated gas > CO2	0.000
CHP: Industrial : Useful Thermal Output - Associated gas > N2O	0.000
CHP: Industrial : Useful Thermal Output - Biomass > CH4	0.013
CHP: Industrial : Useful Thermal Output - Biomass > N2O	0.026
CHP: Industrial : Useful Thermal Output - Bituminous Coal > CH4	0.000

Categories Included in the Inventory.

CHP: Industrial : Useful Thermal Output - Bituminous Coal > CO2	1.724
CHP: Industrial : Useful Thermal Output - Bituminous Coal > N2O	0.009
CHP: Industrial : Useful Thermal Output - Digester Gas > CH4	0.000
CHP: Industrial : Useful Thermal Output - Digester Gas > N2O	0.000
CHP: Industrial : Useful Thermal Output - Distillate > CH4	0.000
CHP: Industrial : Useful Thermal Output - Distillate > CO2	0.049
CHP: Industrial : Useful Thermal Output - Distillate > N2O	0.000
CHP: Industrial : Useful Thermal Output - Landfill Gas > CH4	0.000
CHP: Industrial : Useful Thermal Output - Landfill Gas > N2O	0.000
CHP: Industrial : Useful Thermal Output - Lignite Coal > CH4	0.000
CHP: Industrial : Useful Thermal Output - Lignite Coal > CO2	0.000
CHP: Industrial : Useful Thermal Output - Lignite Coal > N2O	0.000
CHP: Industrial : Useful Thermal Output - Natural Gas > CH4	0.003
CHP: Industrial : Useful Thermal Output - Natural Gas > CO2	6.613
CHP: Industrial : Useful Thermal Output - Natural Gas > N2O	0.004
CHP: Industrial : Useful Thermal Output - Other Coal > CH4	0.000
CHP: Industrial : Useful Thermal Output - Other Coal > CO2	0.007
CHP: Industrial : Useful Thermal Output - Other Coal > N2O	0.000
CHP: Industrial : Useful Thermal Output - Petroleum Coke > CH4	0.000
CHP: Industrial : Useful Thermal Output - Petroleum Coke > CO2	0.302
CHP: Industrial : Useful Thermal Output - Petroleum Coke > N2O	0.001
CHP: Industrial : Useful Thermal Output - Propane > CH4	0.000
CHP: Industrial : Useful Thermal Output - Propane > CO2	0.000
CHP: Industrial : Useful Thermal Output - Propane > N2O	0.000
CHP: Industrial : Useful Thermal Output - Refinery Gas > CH4	0.000
CHP: Industrial : Useful Thermal Output - Refinery Gas > CO2	0.810
CHP: Industrial : Useful Thermal Output - Refinery Gas > N2O	0.000
CHP: Industrial : Useful Thermal Output - Residual Fuel Oil > CH4	0.000
CHP: Industrial : Useful Thermal Output - Residual Fuel Oil > CO2	0.005
CHP: Industrial : Useful Thermal Output - Residual Fuel Oil > N2O	0.000
CHP: Industrial : Useful Thermal Output - Tires > CH4	0.000
CHP: Industrial : Useful Thermal Output - Tires > CO2	0.026
CHP: Industrial : Useful Thermal Output - Tires > N2O	0.000
CHP: Industrial : Useful Thermal Output - Waste Oil > CH4	0.001
CHP: Industrial : Useful Thermal Output - Waste Oil > CO2	0.105
CHP: Industrial : Useful Thermal Output - Waste Oil > N2O	0.002
In State Generation : CHP: Commercial - Biomass > CH4	0.000
In State Generation : CHP: Commercial - Biomass > N2O	0.000
In State Generation : CHP: Commercial - Digester Gas > CH4	0.000
In State Generation : CHP: Commercial - Digester Gas > N2O	0.000
In State Generation : CHP: Commercial - Distillate > CH4	0.000
In State Generation : CHP: Commercial - Distillate > CO2	0.007
In State Generation : CHP: Commercial - Distillate > N2O	0.000
In State Generation : CHP: Commercial - Jet Fuel > CH4	0.000
In State Generation : CHP: Commercial - Jet Fuel > CO2	0.000
In State Generation : CHP: Commercial - Jet Fuel > N2O	0.000
In State Generation : CHP: Commercial - Kerosene > CH4	0.000
In State Generation : CHP: Commercial - Kerosene > CO2	0.000
In State Generation : CHP: Commercial - Kerosene > N2O	0.000
In State Generation : CHP: Commercial - Landfill Gas > CH4	0.000
In State Generation : CHP: Commercial - Landfill Gas > N2O	0.000
In State Generation : CHP: Commercial - Natural Gas > CH4	0.000
In State Generation : CHP: Commercial - Natural Gas > CO2	0.614
In State Generation : CHP: Commercial - Natural Gas > N2O	0.000
In State Generation : CHP: Commercial - Propane > CH4	0.000

Categories Included in the Inventory.

In State Generation : CHP: Commercial - Propane > CO2	0.000
In State Generation : CHP: Commercial - Propane > N2O	0.000
In State Generation : CHP: Commercial - Refinery Gas > CH4	0.000
In State Generation : CHP: Commercial - Refinery Gas > CO2	0.079
In State Generation : CHP: Commercial - Refinery Gas > N2O	0.000
In State Generation : CHP: Commercial - Waste Oil > CH4	0.000
In State Generation : CHP: Commercial - Waste Oil > CO2	0.000
In State Generation : CHP: Commercial - Waste Oil > N2O	0.000
In State Generation : CHP: Industrial - Associated gas > CH4	0.000
In State Generation : CHP: Industrial - Associated gas > CO2	0.000
In State Generation : CHP: Industrial - Associated gas > N2O	0.000
In State Generation : CHP: Industrial - Biomass > CH4	0.019
In State Generation : CHP: Industrial - Biomass > N2O	0.037
In State Generation : CHP: Industrial - Bituminous Coal > CH4	0.000
In State Generation : CHP: Industrial - Bituminous Coal > CO2	2.216
In State Generation : CHP: Industrial - Bituminous Coal > N2O	0.011
In State Generation : CHP: Industrial - Digester Gas > CH4	0.000
In State Generation : CHP: Industrial - Digester Gas > N2O	0.000
In State Generation : CHP: Industrial - Distillate > CH4	0.000
In State Generation : CHP: Industrial - Distillate > CO2	0.014
In State Generation : CHP: Industrial - Distillate > N2O	0.000
In State Generation : CHP: Industrial - Landfill Gas > CH4	0.000
In State Generation : CHP: Industrial - Landfill Gas > N2O	0.000
In State Generation : CHP: Industrial - Lignite Coal > CH4	0.000
In State Generation : CHP: Industrial - Lignite Coal > CO2	0.000
In State Generation : CHP: Industrial - Lignite Coal > N2O	0.000
In State Generation : CHP: Industrial - Natural Gas > CH4	0.004
In State Generation : CHP: Industrial - Natural Gas > CO2	10.594
In State Generation : CHP: Industrial - Natural Gas > N2O	0.006
In State Generation : CHP: Industrial - Other Coal > CH4	0.000
In State Generation : CHP: Industrial - Other Coal > CO2	0.190
In State Generation : CHP: Industrial - Other Coal > N2O	0.001
In State Generation : CHP: Industrial - Petroleum Coke > CH4	0.000
In State Generation : CHP: Industrial - Petroleum Coke > CO2	0.452
In State Generation : CHP: Industrial - Petroleum Coke > N2O	0.001
In State Generation : CHP: Industrial - Propane > CH4	0.000
In State Generation : CHP: Industrial - Propane > CO2	0.000
In State Generation : CHP: Industrial - Propane > N2O	0.000
In State Generation : CHP: Industrial - Refinery Gas > CH4	0.000
In State Generation : CHP: Industrial - Refinery Gas > CO2	0.843
In State Generation : CHP: Industrial - Refinery Gas > N2O	0.000
In State Generation : CHP: Industrial - Residual Fuel Oil > CH4	0.000
In State Generation : CHP: Industrial - Residual Fuel Oil > CO2	0.004
In State Generation : CHP: Industrial - Residual Fuel Oil > N2O	0.000
In State Generation : CHP: Industrial - Tires > CH4	0.000
In State Generation : CHP: Industrial - Tires > CO2	0.063
In State Generation : CHP: Industrial - Tires > N2O	0.000
In State Generation : CHP: Industrial - Waste Oil > CH4	0.001
In State Generation : CHP: Industrial - Waste Oil > CO2	0.082
In State Generation : CHP: Industrial - Waste Oil > N2O	0.001
	27.63

1A1b - Petroleum Refining

Petroleum Refining - Associated gas > CH4	0.000
Petroleum Refining - Associated gas > CO2	0.655
Petroleum Refining - Associated gas > N2O	0.000

Categories Included in the Inventory.

Petroleum Refining - Catalyst Coke > CH4	0.004
Petroleum Refining - Catalyst Coke > CO2	5.147
Petroleum Refining - Catalyst Coke > N2O	0.011
Petroleum Refining - Distillate > CH4	0.000
Petroleum Refining - Distillate > CO2	0.004
Petroleum Refining - Distillate > N2O	0.000
Petroleum Refining - LPG > CH4	0.000
Petroleum Refining - LPG > CO2	0.858
Petroleum Refining - LPG > N2O	0.000
Petroleum Refining - Natural Gas > CH4	0.002
Petroleum Refining - Natural Gas > CO2	4.305
Petroleum Refining - Natural Gas > N2O	0.003
Petroleum Refining - Petroleum Coke > CH4	0.000
Petroleum Refining - Petroleum Coke > CO2	0.597
Petroleum Refining - Petroleum Coke > N2O	0.001
Petroleum Refining - Refinery Gas > CH4	0.005
Petroleum Refining - Refinery Gas > CO2	15.820
Petroleum Refining - Refinery Gas > N2O	0.008
Petroleum Refining - Residual Fuel Oil > CH4	0.000
Petroleum Refining - Residual Fuel Oil > CO2	0.212
Petroleum Refining - Residual Fuel Oil > N2O	0.001
1A1c - Manufacture of Solid Fuels and Other Energy Industries	13.86
1A1cii - Other Energy Industries	*13.858*
Oil & Gas Extraction - Associated gas > CH4	0.002
Oil & Gas Extraction - Associated gas > CO2	5.271
Oil & Gas Extraction - Associated gas > N2O	0.003
Oil & Gas Extraction - Crude oil > CH4	0.002
Oil & Gas Extraction - Crude oil > CO2	2.491
Oil & Gas Extraction - Crude oil > N2O	0.006
Oil & Gas Extraction - Distillate > CH4	0.000
Oil & Gas Extraction - Distillate > CO2	0.210
Oil & Gas Extraction - Distillate > N2O	0.001
Oil & Gas Extraction - Natural Gas > CH4	0.002
Oil & Gas Extraction - Natural Gas > CO2	5.726
Oil & Gas Extraction - Natural Gas > N2O	0.003
Oil & Gas Extraction - Residual Fuel Oil > CH4	0.000
Oil & Gas Extraction - Residual Fuel Oil > CO2	0.013
Oil & Gas Extraction - Residual Fuel Oil > N2O	0.000
Pipelines : Natural Gas Pipelines - Natural Gas > CH4	0.000
Pipelines : Natural Gas Pipelines - Natural Gas > CO2	0.000
Pipelines : Natural Gas Pipelines - Natural Gas > N2O	0.000
Pipelines : Non Natural Gas Pipelines - Natural Gas > CH4	0.000
Pipelines : Non Natural Gas Pipelines - Natural Gas > CO2	0.127
Pipelines : Non Natural Gas Pipelines - Natural Gas > N2O	0.000
1A2 - Manufacturing Industries and Construction	**24.24**
Manufacturing : Primary Metals - Natural Gas > CH4	0.000
Manufacturing : Primary Metals - Natural Gas > CO2	0.943
Manufacturing : Primary Metals - Natural Gas > N2O	0.001
1A2c - Chemicals	0.96
Manufacturing : Chemicals & Allied Products : Fuel Use - Natural Gas > CH4	0.000
Manufacturing : Chemicals & Allied Products : Fuel Use - Natural Gas > CO2	0.960
Manufacturing : Chemicals & Allied Products : Fuel Use - Natural Gas > N2O	0.001

(CO2 equivalence based upon IPCC Second Assessement Report's Global Warming Potentials)

Categories Included in the Inventory.

1A2d - Pulp, Paper and Print	1.91
Manufacturing : Printing & Publishing - Natural Gas > CH4	0.000
Manufacturing : Printing & Publishing - Natural Gas > CO2	0.113
Manufacturing : Printing & Publishing - Natural Gas > N2O	0.000
Manufacturing : Pulp & Paper - Natural Gas > CH4	0.000
Manufacturing : Pulp & Paper - Natural Gas > CO2	0.438
Manufacturing : Pulp & Paper - Natural Gas > N2O	0.000
Manufacturing : Pulp & Paper : Paper Mills - Natural Gas > CH4	0.000
Manufacturing : Pulp & Paper : Paper Mills - Natural Gas > CO2	0.390
Manufacturing : Pulp & Paper : Paper Mills - Natural Gas > N2O	0.000
Manufacturing : Pulp & Paper : Paperboard Mills - Natural Gas > CH4	0.000
Manufacturing : Pulp & Paper : Paperboard Mills - Natural Gas > CO2	0.908
Manufacturing : Pulp & Paper : Paperboard Mills - Natural Gas > N2O	0.001
Manufacturing : Pulp & Paper : Pulp Mills - Natural Gas > CH4	0.000
Manufacturing : Pulp & Paper : Pulp Mills - Natural Gas > CO2	0.063
Manufacturing : Pulp & Paper : Pulp Mills - Natural Gas > N2O	0.000
1A2e - Food Processing, Beverages and Tobacco	3.07
Manufacturing : Food Products - Natural Gas > CH4	0.001
Manufacturing : Food Products - Natural Gas > CO2	1.409
Manufacturing : Food Products - Natural Gas > N2O	0.001
Manufacturing : Food Products : Food Processing - Natural Gas > CH4	0.000
Manufacturing : Food Products : Food Processing - Natural Gas > CO2	1.197
Manufacturing : Food Products : Food Processing - Natural Gas > N2O	0.001
Manufacturing : Food Products : Sugar & Confections - Natural Gas > CH4	0.000
Manufacturing : Food Products : Sugar & Confections - Natural Gas > CO2	0.463
Manufacturing : Food Products : Sugar & Confections - Natural Gas > N2O	0.000
Manufacturing : Tobacco - Natural Gas > CH4	0.000
Manufacturing : Tobacco - Natural Gas > CO2	0.000
Manufacturing : Tobacco - Natural Gas > N2O	0.000
1A2f - Non-Metallic Minerals	5.12
Manufacturing : Stone, Clay, Glass & Cement - Natural Gas > CH4	0.000
Manufacturing : Stone, Clay, Glass & Cement - Natural Gas > CO2	0.845
Manufacturing : Stone, Clay, Glass & Cement - Natural Gas > N2O	0.000
Manufacturing : Stone, Clay, Glass & Cement : Cement - Biomass Waste Fuel > CH4	0.000
Manufacturing : Stone, Clay, Glass & Cement : Cement - Biomass Waste Fuel > N2O	0.000
Manufacturing : Stone, Clay, Glass & Cement : Cement - Coal > CH4	0.006
Manufacturing : Stone, Clay, Glass & Cement : Cement - Coal > CO2	2.890
Manufacturing : Stone, Clay, Glass & Cement : Cement - Coal > N2O	0.014
Manufacturing : Stone, Clay, Glass & Cement : Cement - Distillate > CH4	0.000
Manufacturing : Stone, Clay, Glass & Cement : Cement - Distillate > CO2	0.001
Manufacturing : Stone, Clay, Glass & Cement : Cement - Distillate > N2O	0.000
Manufacturing : Stone, Clay, Glass & Cement : Cement - Fossil Waste Fuel > CH4	0.000
Manufacturing : Stone, Clay, Glass & Cement : Cement - Fossil Waste Fuel > CO2	0.043
Manufacturing : Stone, Clay, Glass & Cement : Cement - Fossil Waste Fuel > N2O	0.001
Manufacturing : Stone, Clay, Glass & Cement : Cement - Natural Gas > CH4	0.000
Manufacturing : Stone, Clay, Glass & Cement : Cement - Natural Gas > CO2	0.154
Manufacturing : Stone, Clay, Glass & Cement : Cement - Natural Gas > N2O	0.000
Manufacturing : Stone, Clay, Glass & Cement : Cement - Petroleum Coke > CH4	0.000
Manufacturing : Stone, Clay, Glass & Cement : Cement - Petroleum Coke > CO2	0.286
Manufacturing : Stone, Clay, Glass & Cement : Cement - Petroleum Coke > N2O	0.001
Manufacturing : Stone, Clay, Glass & Cement : Cement - Residual Fuel Oil > CH4	0.000
Manufacturing : Stone, Clay, Glass & Cement : Cement - Residual Fuel Oil > CO2	0.045
Manufacturing : Stone, Clay, Glass & Cement : Cement - Residual Fuel Oil > N2O	0.000

(CO2 equivalence based upon IPCC Second Assessement Report's Global Warming Potentials)

Categories Included in the Inventory.

Manufacturing : Stone, Clay, Glass & Cement : Cement - Tires > CH4	0.000
Manufacturing : Stone, Clay, Glass & Cement : Cement - Tires > CO2	0.032
Manufacturing : Stone, Clay, Glass & Cement : Cement - Tires > N2O	0.000
Manufacturing : Stone, Clay, Glass & Cement : Flat Glass - Natural Gas > CH4	0.000
Manufacturing : Stone, Clay, Glass & Cement : Flat Glass - Natural Gas > CO2	0.089
Manufacturing : Stone, Clay, Glass & Cement : Flat Glass - Natural Gas > N2O	0.000
Manufacturing : Stone, Clay, Glass & Cement : Glass Containers - Natural Gas > CH4	0.000
Manufacturing : Stone, Clay, Glass & Cement : Glass Containers - Natural Gas > CO2	0.715
Manufacturing : Stone, Clay, Glass & Cement : Glass Containers - Natural Gas > N2O	0.000
1A2g - Transport Equipment	0.53
Manufacturing : Transportation Equip. - Natural Gas > CH4	0.000
Manufacturing : Transportation Equip. - Natural Gas > CO2	0.533
Manufacturing : Transportation Equip. - Natural Gas > N2O	0.000
1A2h - Machinery	1.33
Manufacturing : Electric & Electronic Equip. - Natural Gas > CH4	0.000
Manufacturing : Electric & Electronic Equip. - Natural Gas > CO2	0.097
Manufacturing : Electric & Electronic Equip. - Natural Gas > N2O	0.000
Manufacturing : Electric & Electronic Equip. : Semiconductors & Related Products - Natural Gas > CH4	0.000
Manufacturing : Electric & Electronic Equip. : Semiconductors & Related Products - Natural Gas > CO2	0.188
Manufacturing : Electric & Electronic Equip. : Semiconductors & Related Products - Natural Gas > N2O	0.000
Manufacturing : Electric & Electronic Equip. : Telephone & Broadcasting Equip. - Natural Gas > CH4	0.000
Manufacturing : Electric & Electronic Equip. : Telephone & Broadcasting Equip. - Natural Gas > CO2	0.064
Manufacturing : Electric & Electronic Equip. : Telephone & Broadcasting Equip. - Natural Gas > N2O	0.000
Manufacturing : Instruments & Related Products - Natural Gas > CH4	0.000
Manufacturing : Instruments & Related Products - Natural Gas > CO2	0.071
Manufacturing : Instruments & Related Products - Natural Gas > N2O	0.000
Manufacturing : Metal Durables : Computers & Office Machines - Natural Gas > CH4	0.000
Manufacturing : Metal Durables : Computers & Office Machines - Natural Gas > CO2	0.131
Manufacturing : Metal Durables : Computers & Office Machines - Natural Gas > N2O	0.000
Manufacturing : Metal Durables : Fabricated Metal Products - Natural Gas > CH4	0.000
Manufacturing : Metal Durables : Fabricated Metal Products - Natural Gas > CO2	0.580
Manufacturing : Metal Durables : Fabricated Metal Products - Natural Gas > N2O	0.000
Manufacturing : Metal Durables : Industrial Machinery & Equip. - Natural Gas > CH4	0.000
Manufacturing : Metal Durables : Industrial Machinery & Equip. - Natural Gas > CO2	0.202
Manufacturing : Metal Durables : Industrial Machinery & Equip. - Natural Gas > N2O	0.000
1A2i - Mining (excluding fuels) and Quarrying	0.03
Mining : Coal - Natural Gas > CH4	0.000
Mining : Coal - Natural Gas > CO2	0.000
Mining : Coal - Natural Gas > N2O	0.000
Mining : Metals - Natural Gas > CH4	0.000
Mining : Metals - Natural Gas > CO2	0.000
Mining : Metals - Natural Gas > N2O	0.000
Mining : Non Metals - Natural Gas > CH4	0.000
Mining : Non Metals - Natural Gas > CO2	0.027
Mining : Non Metals - Natural Gas > N2O	0.000
1A2j - Wood and Wood Products	0.24
Manufacturing : Wood & Furniture : Furniture & Fixtures - Natural Gas > CH4	0.000
Manufacturing : Wood & Furniture : Furniture & Fixtures - Natural Gas > CO2	0.052
Manufacturing : Wood & Furniture : Furniture & Fixtures - Natural Gas > N2O	0.000
Manufacturing : Wood & Furniture : Lumber & Wood Products - Natural Gas > CH4	0.000

(CO2 equivalence based upon IPCC Second Assessement Report's Global Warming Potentials)

Categories Included in the Inventory.

Manufacturing : Wood & Furniture : Lumber & Wood Products - Natural Gas > CO2	0.184
Manufacturing : Wood & Furniture : Lumber & Wood Products - Natural Gas > N2O	0.000
1A2k - Construction	0.67
Manufacturing : Construction - Gasoline > CH4	0.000
Manufacturing : Construction - Gasoline > CO2	0.540
Manufacturing : Construction - Gasoline > N2O	0.001
Manufacturing : Construction - Natural Gas > CH4	0.000
Manufacturing : Construction - Natural Gas > CO2	0.125
Manufacturing : Construction - Natural Gas > N2O	0.000
1A2l - Textile and Leather	0.38
Manufacturing : Textiles : Apparel - Natural Gas > CH4	0.000
Manufacturing : Textiles : Apparel - Natural Gas > CO2	0.043
Manufacturing : Textiles : Apparel - Natural Gas > N2O	0.000
Manufacturing : Textiles : Leather - Natural Gas > CH4	0.000
Manufacturing : Textiles : Leather - Natural Gas > CO2	0.008
Manufacturing : Textiles : Leather - Natural Gas > N2O	0.000
Manufacturing : Textiles : Textile Mills - Natural Gas > CH4	0.000
Manufacturing : Textiles : Textile Mills - Natural Gas > CO2	0.327
Manufacturing : Textiles : Textile Mills - Natural Gas > N2O	0.000
1A2m - Non-specified Industry.	9.04
Manufacturing - Coal > CH4	0.001
Manufacturing - Coal > CO2	0.552
Manufacturing - Coal > N2O	0.003
Manufacturing - Distillate > CH4	0.003
Manufacturing - Distillate > CO2	3.934
Manufacturing - Distillate > N2O	0.010
Manufacturing - Gasoline > CH4	0.001
Manufacturing - Gasoline > CO2	1.182
Manufacturing - Gasoline > N2O	0.003
Manufacturing - Kerosene > CH4	0.000
Manufacturing - Kerosene > CO2	0.008
Manufacturing - Kerosene > N2O	0.000
Manufacturing - LPG > CH4	0.001
Manufacturing - LPG > CO2	1.982
Manufacturing - LPG > N2O	0.001
Manufacturing - Natural Gas > CH4	0.000
Manufacturing - Natural Gas > CO2	0.038
Manufacturing - Natural Gas > N2O	0.000
Manufacturing - Natural Gas Liquids > CH4	0.000
Manufacturing - Natural Gas Liquids > CO2	0.330
Manufacturing - Natural Gas Liquids > N2O	0.001
Manufacturing - Residual Fuel Oil > CH4	0.001
Manufacturing - Residual Fuel Oil > CO2	0.636
Manufacturing - Residual Fuel Oil > N2O	0.002
Manufacturing : Plastics & Rubber - Natural Gas > CH4	0.000
Manufacturing : Plastics & Rubber - Natural Gas > CO2	0.049
Manufacturing : Plastics & Rubber - Natural Gas > N2O	0.000
Manufacturing : Plastics & Rubber : Plastics - Natural Gas > CH4	0.000
Manufacturing : Plastics & Rubber : Plastics - Natural Gas > CO2	0.185
Manufacturing : Plastics & Rubber : Plastics - Natural Gas > N2O	0.000
Not Specified Industrial - Wood (Wet) > CH4	0.041
Not Specified Industrial - Wood (Wet) > N2O	0.081

Categories Included in the Inventory.

1A3 - Transport	**150.02**
Not Specified Transportation - Distillate > CH4	0.003
Not Specified Transportation - Distillate > CO2	2.132
Not Specified Transportation - Distillate > N2O	0.017
Not Specified Transportation - LPG > CH4	0.000
Not Specified Transportation - LPG > CO2	0.208
Not Specified Transportation - LPG > N2O	0.000
Not Specified Transportation - Residual Fuel Oil > CH4	0.000
Not Specified Transportation - Residual Fuel Oil > CO2	0.000
Not Specified Transportation - Residual Fuel Oil > N2O	0.000
1A3a - Civil Aviation	5.13
Aviation - Natural Gas > CH4	0.000
Aviation - Natural Gas > CO2	0.018
Aviation - Natural Gas > N2O	0.000
1A3aii - Domestic Aviation	*5.113*
Aviation : Domestic Air transport - Aviation Gasoline > CH4	0.007
Aviation : Domestic Air transport - Aviation Gasoline > CO2	0.386
Aviation : Domestic Air transport - Aviation Gasoline > N2O	0.002
Aviation : Domestic Air transport : Intrastate - Jet Fuel > CH4	0.003
Aviation : Domestic Air transport : Intrastate - Jet Fuel > CO2	4.671
Aviation : Domestic Air transport : Intrastate - Jet Fuel > N2O	0.045
1A3b - Road Transportation	137.99
On road : Freight - Natural Gas > CH4	0.000
On road : Freight - Natural Gas > CO2	0.016
On road : Freight - Natural Gas > N2O	0.000
On road : Passenger - Natural Gas > CH4	0.000
On road : Passenger - Natural Gas > CO2	0.010
On road : Passenger - Natural Gas > N2O	0.000
On road : Passenger : Taxis & Buses - Natural Gas > CH4	0.000
On road : Passenger : Taxis & Buses - Natural Gas > CO2	0.010
On road : Passenger : Taxis & Buses - Natural Gas > N2O	0.000
1A3bi - Cars	*63.746*
On road : Passenger cars - Distillate > CH4	0.001
On road : Passenger cars - Distillate > CO2	0.610
On road : Passenger cars - Distillate > N2O	0.006
On road : Passenger cars - Gasoline > CH4	0.436
On road : Passenger cars - Gasoline > CO2	59.676
On road : Passenger cars - Gasoline > N2O	3.017
1A3bii - Light-duty Trucks	*44.754*
On road : Light-Duty Trucks - Distillate > CH4	0.000
On road : Light-Duty Trucks - Distillate > CO2	0.520
On road : Light-Duty Trucks - Distillate > N2O	0.005
On road : Light-Duty Trucks - Gasoline > CH4	0.317
On road : Light-Duty Trucks - Gasoline > CO2	41.337
On road : Light-Duty Trucks - Gasoline > N2O	2.574
1A3biii - Heavy-duty Trucks and Buses	*29.031*
On road : Heavy-Duty Vehicles - Distillate > CH4	0.021
On road : Heavy-Duty Vehicles - Distillate > CO2	17.401
On road : Heavy-Duty Vehicles - Distillate > N2O	0.176
On road : Heavy-Duty Vehicles - Gasoline > CH4	0.140
On road : Heavy-Duty Vehicles - Gasoline > CO2	10.582

California Greenhouse Gas Inventory for 1990 (millions of tonnes of CO2 equivalent)

(CO2 equivalence based upon IPCC Second Assessement Report's Global Warming Potentials)

Categories Included in the Inventory.

On road : Heavy-Duty Vehicles - Gasoline > N2O	0.711
1A3biv - Motorcycles	*0.426*
On road : Motorcycles - Gasoline > CH4	0.017
On road : Motorcycles - Gasoline > CO2	0.376
On road : Motorcycles - Gasoline > N2O	0.032
1A3c - Railways	2.33
Rail - Distillate > CH4	0.004
Rail - Distillate > CO2	2.290
Rail - Distillate > N2O	0.018
Rail - Natural Gas > CH4	0.000
Rail - Natural Gas > CO2	0.019
Rail - Natural Gas > N2O	0.000
1A3d - Water-borne Navigation	2.21
1A3di - International Water-borne Navigation (International Bunkers)	*0.548*
Water-borne : International : Port activities - Distillate > CH4	0.000
Water-borne : International : Port activities - Distillate > CO2	0.020
Water-borne : International : Port activities - Distillate > N2O	0.001
Water-borne : International : Port activities - Residual Fuel Oil > CH4	0.000
Water-borne : International : Port activities - Residual Fuel Oil > CO2	0.143
Water-borne : International : Port activities - Residual Fuel Oil > N2O	0.002
Water-borne : International : Transit (CA waters) - Distillate > CH4	0.000
Water-borne : International : Transit (CA waters) - Distillate > CO2	0.007
Water-borne : International : Transit (CA waters) - Distillate > N2O	0.000
Water-borne : International : Transit (CA waters) - Residual Fuel Oil > CH4	0.001
Water-borne : International : Transit (CA waters) - Residual Fuel Oil > CO2	0.369
Water-borne : International : Transit (CA waters) - Residual Fuel Oil > N2O	0.004
1A3dii - Domestic Water-borne Navigation	*1.662*
Water-borne - Natural Gas > CH4	0.000
Water-borne - Natural Gas > CO2	0.001
Water-borne - Natural Gas > N2O	0.000
Water-borne : Interstate : Port activities - Distillate > CH4	0.000
Water-borne : Interstate : Port activities - Distillate > CO2	0.006
Water-borne : Interstate : Port activities - Distillate > N2O	0.000
Water-borne : Interstate : Port activities - Residual Fuel Oil > CH4	0.000
Water-borne : Interstate : Port activities - Residual Fuel Oil > CO2	0.068
Water-borne : Interstate : Port activities - Residual Fuel Oil > N2O	0.001
Water-borne : Interstate : Transit (CA waters) - Distillate > CH4	0.000
Water-borne : Interstate : Transit (CA waters) - Distillate > CO2	0.002
Water-borne : Interstate : Transit (CA waters) - Distillate > N2O	0.000
Water-borne : Interstate : Transit (CA waters) - Residual Fuel Oil > CH4	0.000
Water-borne : Interstate : Transit (CA waters) - Residual Fuel Oil > CO2	0.146
Water-borne : Interstate : Transit (CA waters) - Residual Fuel Oil > N2O	0.002
Water-borne : Intrastate : Harbor craft - Distillate > CH4	0.003
Water-borne : Intrastate : Harbor craft - Distillate > CO2	1.167
Water-borne : Intrastate : Harbor craft - Distillate > N2O	0.046
Water-borne : Intrastate : Port activities - Distillate > CH4	0.000
Water-borne : Intrastate : Port activities - Distillate > CO2	0.014
Water-borne : Intrastate : Port activities - Distillate > N2O	0.001
Water-borne : Intrastate : Port activities - Residual Fuel Oil > CH4	0.000
Water-borne : Intrastate : Port activities - Residual Fuel Oil > CO2	0.118
Water-borne : Intrastate : Port activities - Residual Fuel Oil > N2O	0.002
Water-borne : Intrastate : Transit (CA waters) - Distillate > CH4	0.000
Water-borne : Intrastate : Transit (CA waters) - Distillate > CO2	0.002

Categories Included in the Inventory.

Water-borne : Intrastate : Transit (CA waters) - Distillate > N2O	0.000
Water-borne : Intrastate : Transit (CA waters) - Residual Fuel Oil > CH4	0.000
Water-borne : Intrastate : Transit (CA waters) - Residual Fuel Oil > CO2	0.082
Water-borne : Intrastate : Transit (CA waters) - Residual Fuel Oil > N2O	0.001
1A4 - Other Sectors	**48.19**
1A4a - Commercial/Institutional	14.03
Communication - Natural Gas > CH4	0.000
Communication - Natural Gas > CO2	0.002
Communication - Natural Gas > N2O	0.000
Communication : Other Message Communications - Natural Gas > CH4	0.000
Communication : Other Message Communications - Natural Gas > CO2	0.000
Communication : Other Message Communications - Natural Gas > N2O	0.000
Communication : Radio Broadcasting Stations - Natural Gas > CH4	0.000
Communication : Radio Broadcasting Stations - Natural Gas > CO2	0.005
Communication : Radio Broadcasting Stations - Natural Gas > N2O	0.000
Communication : Telephone & Cell Phone Services - Natural Gas > CH4	0.000
Communication : Telephone & Cell Phone Services - Natural Gas > CO2	0.048
Communication : Telephone & Cell Phone Services - Natural Gas > N2O	0.000
Communication : U.S. Postal Service - Natural Gas > CH4	0.000
Communication : U.S. Postal Service - Natural Gas > CO2	0.014
Communication : U.S. Postal Service - Natural Gas > N2O	0.000
Domestic Utilities : Electricity, Natural Gas & Steam - Natural Gas > CH4	0.000
Domestic Utilities : Electricity, Natural Gas & Steam - Natural Gas > CO2	0.141
Domestic Utilities : Electricity, Natural Gas & Steam - Natural Gas > N2O	0.000
Domestic Utilities : Sewerage Systems - Natural Gas > CH4	0.000
Domestic Utilities : Sewerage Systems - Natural Gas > CO2	0.074
Domestic Utilities : Sewerage Systems - Natural Gas > N2O	0.000
Domestic Utilities : Streetlights - Natural Gas > CH4	0.000
Domestic Utilities : Streetlights - Natural Gas > CO2	0.001
Domestic Utilities : Streetlights - Natural Gas > N2O	0.000
Domestic Utilities : Water Supply - Natural Gas > CH4	0.000
Domestic Utilities : Water Supply - Natural Gas > CO2	0.122
Domestic Utilities : Water Supply - Natural Gas > N2O	0.000
Education : College - Natural Gas > CH4	0.001
Education : College - Natural Gas > CO2	0.696
Education : College - Natural Gas > N2O	0.000
Education : School - Natural Gas > CH4	0.001
Education : School - Natural Gas > CO2	0.717
Education : School - Natural Gas > N2O	0.000
Food Services : Food & Liquor - Natural Gas > CH4	0.001
Food Services : Food & Liquor - Natural Gas > CO2	0.255
Food Services : Food & Liquor - Natural Gas > N2O	0.000
Food Services : Restaurant - Natural Gas > CH4	0.003
Food Services : Restaurant - Natural Gas > CO2	1.633
Food Services : Restaurant - Natural Gas > N2O	0.001
Health Care - Natural Gas > CH4	0.003
Health Care - Natural Gas > CO2	1.320
Health Care - Natural Gas > N2O	0.001
Hotels - Natural Gas > CH4	0.001
Hotels - Natural Gas > CO2	0.669
Hotels - Natural Gas > N2O	0.000
National Security - Natural Gas > CH4	0.001
National Security - Natural Gas > CO2	0.563
National Security - Natural Gas > N2O	0.000

Categories Included in the Inventory.

Not Specified Commercial - Coal > CH4	0.000
Not Specified Commercial - Coal > CO2	0.055
Not Specified Commercial - Coal > N2O	0.000
Not Specified Commercial - Distillate > CH4	0.005
Not Specified Commercial - Distillate > CO2	1.799
Not Specified Commercial - Distillate > N2O	0.005
Not Specified Commercial - Gasoline > CH4	0.002
Not Specified Commercial - Gasoline > CO2	0.720
Not Specified Commercial - Gasoline > N2O	0.002
Not Specified Commercial - Kerosene > CH4	0.000
Not Specified Commercial - Kerosene > CO2	0.069
Not Specified Commercial - Kerosene > N2O	0.000
Not Specified Commercial - LPG > CH4	0.000
Not Specified Commercial - LPG > CO2	0.229
Not Specified Commercial - LPG > N2O	0.000
Not Specified Commercial - Natural Gas > CH4	0.004
Not Specified Commercial - Natural Gas > CO2	2.238
Not Specified Commercial - Natural Gas > N2O	0.001
Not Specified Commercial - Residual Fuel Oil > CH4	0.001
Not Specified Commercial - Residual Fuel Oil > CO2	0.414
Not Specified Commercial - Residual Fuel Oil > N2O	0.001
Not Specified Commercial - Wood (Wet) > CH4	0.025
Not Specified Commercial - Wood (Wet) > N2O	0.005
Offices - Natural Gas > CH4	0.003
Offices - Natural Gas > CO2	1.452
Offices - Natural Gas > N2O	0.001
Retail & Wholesale : Refrigerated Warehousing - Natural Gas > CH4	0.000
Retail & Wholesale : Refrigerated Warehousing - Natural Gas > CO2	0.079
Retail & Wholesale : Refrigerated Warehousing - Natural Gas > N2O	0.000
Retail & Wholesale : Retail - Natural Gas > CH4	0.001
Retail & Wholesale : Retail - Natural Gas > CO2	0.289
Retail & Wholesale : Retail - Natural Gas > N2O	0.000
Retail & Wholesale : Warehousing - Natural Gas > CH4	0.001
Retail & Wholesale : Warehousing - Natural Gas > CO2	0.313
Retail & Wholesale : Warehousing - Natural Gas > N2O	0.000
Transportation Services : Airports - Natural Gas > CH4	0.000
Transportation Services : Airports - Natural Gas > CO2	0.024
Transportation Services : Airports - Natural Gas > N2O	0.000
Transportation Services : Transportation - Natural Gas > CH4	0.000
Transportation Services : Transportation - Natural Gas > CO2	0.007
Transportation Services : Transportation - Natural Gas > N2O	0.000
Transportation Services : Water Transportation - Natural Gas > CH4	0.000
Transportation Services : Water Transportation - Natural Gas > CO2	0.004
Transportation Services : Water Transportation - Natural Gas > N2O	0.000
	29.66

1A4b - Residential

Household Use - Distillate > CH4	0.000
Household Use - Distillate > CO2	0.089
Household Use - Distillate > N2O	0.000
Household Use - Kerosene > CH4	0.000
Household Use - Kerosene > CO2	0.054
Household Use - Kerosene > N2O	0.000
Household Use - LPG > CH4	0.002
Household Use - LPG > CO2	1.298
Household Use - LPG > N2O	0.001

(CO2 equivalence based upon IPCC Second Assessement Report's Global Warming Potentials)

Categories Included in the Inventory.

Household Use - Natural Gas > CH4	0.055
Household Use - Natural Gas > CO2	27.663
Household Use - Natural Gas > N2O	0.016
Household Use - Wood (Wet) > CH4	0.400
Household Use - Wood (Wet) > N2O	0.079
1A4c - Agriculture/Forestry/Fishing/Fish Farms	4.50
Ag Energy Use - Distillate > CH4	0.010
Ag Energy Use - Distillate > CO2	3.355
Ag Energy Use - Distillate > N2O	0.009
Ag Energy Use - Gasoline > CH4	0.001
Ag Energy Use - Gasoline > CO2	0.433
Ag Energy Use - Gasoline > N2O	0.001
Ag Energy Use - Kerosene > CH4	0.000
Ag Energy Use - Kerosene > CO2	0.002
Ag Energy Use - Kerosene > N2O	0.000
Ag Energy Use - LPG > CH4	0.000
Ag Energy Use - LPG > CO2	0.154
Ag Energy Use - LPG > N2O	0.000
Ag Energy Use - Natural Gas > CH4	0.000
Ag Energy Use - Natural Gas > CO2	0.000
Ag Energy Use - Natural Gas > N2O	0.000
Ag Energy Use : Crop Production - Natural Gas > CH4	0.001
Ag Energy Use : Crop Production - Natural Gas > CO2	0.447
Ag Energy Use : Crop Production - Natural Gas > N2O	0.000
Ag Energy Use : Irrigation - Natural Gas > CH4	0.000
Ag Energy Use : Irrigation - Natural Gas > CO2	0.038
Ag Energy Use : Irrigation - Natural Gas > N2O	0.000
Ag Energy Use : Livestock - Natural Gas > CH4	0.000
Ag Energy Use : Livestock - Natural Gas > CO2	0.053
Ag Energy Use : Livestock - Natural Gas > N2O	0.000
1A5 - Non-Specified	**1.38**
Flaring - Natural Gas > CH4	0.000
Flaring - Natural Gas > CO2	0.149
Flaring - Natural Gas > N2O	0.000
Not Specified Not Specified - LPG > CH4	0.000
Not Specified Not Specified - LPG > CO2	0.134
Not Specified Not Specified - LPG > N2O	0.000
Not Specified Not Specified - Natural Gas > CH4	0.000
Not Specified Not Specified - Natural Gas > CO2	1.097
Not Specified Not Specified - Natural Gas > N2O	0.001
1B - Fugitive Emissions from Fuels	***5.25***
1B2 - Oil and Natural Gas	**2.94**
Manufacturing : Chemicals & Allied Products : Fugitives > Fugitive emissions > CH4	0.022
Manufacturing : Construction : Fugitives > Fugitive emissions > CH4	0.005
Manufacturing : Electric & Electronic Equip. : Fugitives > Fugitive emissions > CH4	0.000
Manufacturing : Food Products : Fugitives > Fugitive emissions > CH4	0.013
Manufacturing : Fugitives > Fugitive emissions > CH4	0.046
Manufacturing : Plastics & Rubber : Fugitives > Fugitive emissions > CH4	0.007
Manufacturing : Primary Metals : Fugitives > Fugitive emissions > CH4	0.001
Manufacturing : Pulp & Paper : Fugitives > Fugitive emissions > CH4	0.004
Manufacturing : Stone, Clay, Glass & Cement : Fugitives > Fugitive emissions > CH4	0.006

California Greenhouse Gas Inventory for 1990 (millions of tonnes of CO2 equivalent)

(CO2 equivalence based upon IPCC Second Assessement Report's Global Warming Potentials)

Categories Included in the Inventory.

Manufacturing : Storage Tanks : Fugitives > Fugitive emissions > CH4	0.000
Not Specified Industrial : Fugitives > Fugitive emissions > CH4	0.263
Oil & Gas Extraction : Petroleum Gas Seeps : Fugitives > Fugitive emissions > CH4	0.241
Oil & Gas Extraction : Process Losses : Fugitives > Fugitive emissions > CH4	0.418
Oil & Gas Extraction : Storage Tanks : Fugitives > Fugitive emissions > CH4	0.257
Petroleum Marketing : Process Losses : Fugitives > Fugitive emissions > CH4	0.008
Petroleum Marketing : Storage Tanks : Fugitives > Fugitive emissions > CH4	0.008
1B2a - Oil	0.14
1B2aiii - All Other	*0.139*
Petroleum Refining : Process Losses : Fugitives > Fugitive emissions > CH4	0.137
Petroleum Refining : Storage Tanks : Fugitives > Fugitive emissions > CH4	0.002
1B2b - Natural Gas	1.50
Pipelines : Natural Gas : Fugitives > Fugitive emissions > CH4	1.505
1B3 - Other Emissions from Energy Production	**2.31**
In State Generation : Merchant Owned > Geothermal power - Geothermal > CO2	0.968
In State Generation : Utility Owned > Geothermal power - Geothermal > CO2	1.339
2 - Industrial Processes and Product Use	**18.34**
2A - Mineral Industry	***4.85***
2A1 - Cement Production	**4.62**
Manufacturing : Stone, Clay, Glass & Cement : Cement > Clinker production > CO2	4.619
2A2 - Lime Production	**0.23**
Manufacturing : Stone, Clay, Glass & Cement : Lime > Lime production > CO2	0.234
2B - Chemical Industry	***2.34***
Manufacturing : Chemicals & Allied Products > Fuel consumption - LPG > CO2	0.052
Manufacturing : Chemicals & Allied Products > Fuel consumption - Natural Gas > CO2	0.862
Manufacturing : Chemicals & Allied Products > Fuel consumption - Petroleum feedstocks > CO2	0.894
2B2 - Nitric Acid Production	**0.53**
Manufacturing : Chemicals & Allied Products : Nitric Acid > Nitric acid production > N2O	0.535
2D - Non-Energy Products from Fuels and Solvent Use	***2.29***
2D1 - Lubricant Use	**1.13**
Not Specified Industrial > Fuel consumption - Lubricants > CO2	0.484
Not Specified Transportation > Fuel consumption - Lubricants > CO2	0.646
2D2 - Paraffin Wax Use	**0.00**
Not Specified Industrial > Fuel consumption - Waxes > CO2	0.000
2D4 - Other (please specify)	**1.16**
Not Specified Industrial > Fuel consumption - Asphalt > CO2	0.000
Not Specified Industrial > Fuel consumption - Naphtha > CO2	0.938
Not Specified Industrial > Fuel consumption - Other Petroleum Products > CO2	0.219
2E - Electronics Industry	***0.59***
Manufacturing : Electric & Electronic Equip. : Semiconductors & Related Products > Semiconductor manufacture > Halogenated gases (in CO2 Eq.)	0.592
2F - Product Uses as Substitutes for Ozone Depleting Substances	***0.04***
Not Specified Not Specified > Use of substitutes for ozone depleting substances > CF4	0.000
Not Specified Not Specified > Use of substitutes for ozone depleting substances > HFC-125	0.000

(CO2 equivalence based upon IPCC Second Assessement Report's Global Warming Potentials)

Categories Included in the Inventory.

Not Specified Not Specified > Use of substitutes for ozone depleting substances > HFC-134a	0.000
Not Specified Not Specified > Use of substitutes for ozone depleting substances > HFC-143a	0.000
Not Specified Not Specified > Use of substitutes for ozone depleting substances > HFC-23	0.000
Not Specified Not Specified > Use of substitutes for ozone depleting substances > HFC-236fa	0.000
Not Specified Not Specified > Use of substitutes for ozone depleting substances > HFC-32	0.000
Not Specified Not Specified > Use of substitutes for ozone depleting substances > Other ODS substitutes	0.036
2G - Other Product Manufacture and Use	***3.18***
2G1 - Electrical Equipment	**2.58**
2G1b - Use of Electrical Equipment	2.58
Imported Electricity : Transmission and Distribution > SF6 use > SF6	1.016
In State Generation : Transmission and Distribution > SF6 use > SF6	1.561
2G4 - Other (Please specify)	**0.61**
Not Specified Industrial > CO2 Consumption > CO2	0.129
Not Specified Industrial > Limestone and dolomite consumption > CO2	0.138
Not Specified Industrial > Soda ash consumption > CO2	0.341
2H - Other	***5.05***
2H3 - Other (please specify)	**5.05**
Petroleum Refining : Transformation > Fuel consumption - Naphtha > CO2	0.416
Petroleum Refining : Transformation > Fuel consumption - Natural Gas > CO2	2.100
Petroleum Refining : Transformation > Fuel consumption - Natural Gas Liquids > CO2	0.275
Petroleum Refining : Transformation > Fuel consumption - Refinery Gas > CO2	2.100
Petroleum Refining : Transformation > Fuel consumption - Residual Fuel Oil > CO2	0.154
3 - Agriculture, Forestry and Other Land Use	**19.11**
3A - Livestock	***11.67***
3A1 - Enteric Fermentation	**6.67**
3A1a - Cattle	6.25
3A1ai - Dairy Cows	*3.632*
Livestock population - Dairy Cows > CH4	3.014
Livestock population - Dairy replacements 12-23 months > CH4	0.488
Livestock population - Dairy replacements 7-11 months > CH4	0.129
3A1aii - Other Cattle	*2.618*
Livestock population - Beef Cows > CH4	1.480
Livestock population - Beef replacements 12-23 months > CH4	0.115
Livestock population - Beef replacements 7-11 months > CH4	0.031
Livestock population - Bulls > CH4	0.079
Livestock population - Heifer Feedlot > CH4	0.122
Livestock population - Heifer Stockers > CH4	0.115
Livestock population - Steer Feedlot > CH4	0.243
Livestock population - Steer Stockers > CH4	0.434
3A1c - Sheep	0.17
Livestock population - Sheep > CH4	0.168
3A1d - Goats	0.00
Livestock population - Goats > CH4	0.004
3A1f - Horses	0.24
Livestock population - Horses > CH4	0.240
3A1h - Swine	0.01

Categories Included in the Inventory.

Livestock population - Swine > CH4	0.006
3A2 - Manure Management	**5.00**
3A2a - Cattle	4.68
3A2ai - Dairy Cows	*4.359*
Livestock population - Dairy Cows > CH4	4.012
Livestock population - Dairy Cows > N2O	0.084
Livestock population - Dairy Heifers > CH4	0.027
Livestock population - Dairy Heifers > N2O	0.237
3A2aii - Other Cattle	*0.324*
Livestock population - Feedlot - Heifers 500+ lbs > CH4	0.008
Livestock population - Feedlot - Heifers 500+ lbs > N2O	0.041
Livestock population - Feedlot - Steers 500+ lbs > CH4	0.030
Livestock population - Feedlot - Steers 500+ lbs > N2O	0.167
Livestock population - Not on Feed - Beef Cows > CH4	0.044
Livestock population - Not on Feed - Beef Cows > N2O	0.000
Livestock population - Not on Feed - Bulls 500+ lbs > CH4	0.004
Livestock population - Not on Feed - Bulls 500+ lbs > N2O	0.000
Livestock population - Not on Feed - Calves <500 lbs > CH4	0.012
Livestock population - Not on Feed - Calves <500 lbs > N2O	0.000
Livestock population - Not on Feed - Heifers 500+ lbs > CH4	0.009
Livestock population - Not on Feed - Heifers 500+ lbs > N2O	0.000
Livestock population - Not on Feed - Steers 500+ lbs > CH4	0.010
Livestock population - Not on Feed - Steers 500+ lbs > N2O	0.000
3A2c - Sheep	0.02
Livestock population - Sheep > CH4	0.016
Livestock population - Sheep > N2O	0.002
3A2d - Goats	0.00
Livestock population - Goats > CH4	0.000
Livestock population - Goats > N2O	0.000
3A2f - Horses	0.03
Livestock population - Horses > CH4	0.035
Livestock population - Horses > N2O	0.000
3A2h - Swine	0.07
Livestock population - Swine - Breeding > CH4	0.017
Livestock population - Swine - Breeding > N2O	0.000
Livestock population - Swine - Market <60 lbs > CH4	0.010
Livestock population - Swine - Market <60 lbs > N2O	0.000
Livestock population - Swine - Market 120-179 lbs > CH4	0.013
Livestock population - Swine - Market 120-179 lbs > N2O	0.000
Livestock population - Swine - Market 180+ lbs > CH4	0.015
Livestock population - Swine - Market 180+ lbs > N2O	0.000
Livestock population - Swine - Market 60-119 lbs > CH4	0.012
Livestock population - Swine - Market 60-119 lbs > N2O	0.000
3A2i - Poultry	0.20
Livestock population - Broilers > CH4	0.016
Livestock population - Broilers > N2O	0.007
Livestock population - Hens 1+ yr > CH4	0.096
Livestock population - Hens 1+ yr > N2O	0.019
Livestock population - Other Chickens > CH4	0.001
Livestock population - Other Chickens > N2O	0.000
Livestock population - Pullets > CH4	0.018

Categories Included in the Inventory.

Livestock population - Pullets > N2O	0.003
Livestock population - Turkeys > CH4	0.024
Livestock population - Turkeys > N2O	0.012
	0.19
3B - Land	
	0.19
3B1 - Forest Land	
Fire - Forest > N2O	0.013
Fire - Rangeland > N2O	0.003
Fire and other disturbances - Forest > CH4	0.153
Fire and other disturbances - Rangeland > CH4	0.022
3C - Aggregate Sources and Non-CO2 Emissions Sources on Land	***7.26***
3C1 - Emissions from Biomass Burning	**0.12**
3C1b - Biomass Burning in Croplands	0.12
Crop acreage burned - Almond > CH4	0.006
Crop acreage burned - Almond > N2O	0.016
Crop acreage burned - Barley > CH4	0.001
Crop acreage burned - Barley > N2O	0.002
Crop acreage burned - Corn > CH4	0.002
Crop acreage burned - Corn > N2O	0.001
Crop acreage burned - Rice > CH4	0.015
Crop acreage burned - Rice > N2O	0.060
Crop acreage burned - Walnut > CH4	0.004
Crop acreage burned - Walnut > N2O	0.008
Crop acreage burned - Wheat > CH4	0.005
Crop acreage burned - Wheat > N2O	0.004
3C2 - Liming	**0.07**
Dolomite applied to soils > CO2	0.000
Limestone applied to soils > CO2	0.072
3C4 - Direct N2O Emissions from Managed Soils	**5.20**
Histosols cultivation > N2O	0.181
Nitrogen applied in fertilizer - Organic fertilizers > N2O	0.012
Nitrogen applied in fertilizer - Synthetic fertilizers > N2O	2.239
Nitrogen fixed by legume crops > N2O	1.052
Nitrogen in crop residues > N2O	0.093
Nitrogen in manure deposited on pasture/range > N2O	1.549
Nitrogen in manure spread daily > N2O	0.078
3C5 - Indirect N2O Emissions from Managed Soils	**1.44**
Nitrogen applied in fertilizer - Organic fertilizers > N2O	0.003
Nitrogen applied in fertilizer - Synthetic fertilizers > N2O	0.249
Nitrogen applied in fertilizer (leaching & runoff) - Organic fertilizers > N2O	0.003
Nitrogen applied in fertilizer (leaching & runoff) - Synthetic fertilizers > N2O	0.504
Nitrogen in manure (leaching & runoff) > N2O	0.325
Nitrogen volatilized from manure on soils > N2O	0.361
3C7 - Rice Cultivations	**0.41**
Harvested rice area > CH4	0.410

California Greenhouse Gas Inventory for 1990 (millions of tonnes of CO2 equivalent)

(CO2 equivalence based upon IPCC Second Assessement Report's Global Warming Potentials)

Categories Included in the Inventory.

4 - Waste	**9.42**
4A - Solid Waste Disposal	***6.26***
4A1 - Managed Waste Disposal Sites	**6.26**
Landfills > Landfill emissions - Landfill Gas > CH4	6.256
Landfills > Landfill emissions - Landfill Gas > N2O	0.000
4D - Wastewater Treatment and Discharge	***3.17***
4D1 - Domestic Wastewater Treatment and Discharge	**2.83**
Waste water treatment : Domestic Waste Water > California Population > CH4	2.008
Waste water treatment : Domestic Waste Water > California Population > N2O	0.826
4D2 - Industrial Wastewater Treatment and Discharge	**0.34**
Manufacturing : Wastewater Treatment : Fugitives > Fugitive emissions > CH4	0.000
Oil & Gas Extraction : Wastewater Treatment : Fugitives > Fugitive emissions > CH4	0.000
Petroleum Marketing : Wastewater Treatment : Fugitives > Fugitive emissions > CH4	0.000
Petroleum Refining : Wastewater Treatment : Fugitives > Fugitive emissions > CH4	0.002
Waste water treatment : Industrial Waste Water > Production Processed - Fruit and Vegetables > CH4	0.222
Waste water treatment : Industrial Waste Water > Production Processed - Poultry > CH4	0.042
Waste water treatment : Industrial Waste Water > Production Processed - Red Meat > CH4	0.069

Summary of Categories Included in the Inventory.

Gross California Emissions	**433.29**
Sinks and Sequestrations from Rangelands and Forestry	**-6.69**
Net California Emissions	**426.60**

California Greenhouse Gas Inventory for 1990 (millions of tonnes of CO2 equivalent)

(CO2 equivalence based upon IPCC Second Assessement Report's Global Warming Potentials)

Categories Excluded from the Inventory.

1 - Energy	**59.02**
1A - Fuel Combustion Activities	***59.02***
1A3 - Transport	**59.02**
1A3a - Civil Aviation	33.95
1A3ai - International Aviation (International Bunkers)	*14.597*
Aviation : International Civil Aviation - Jet Fuel > CH4 (Excluded)	0.008
Aviation : International Civil Aviation - Jet Fuel > CO2 (Excluded)	14.449
Aviation : International Civil Aviation - Jet Fuel > N2O (Excluded)	0.140
1A3aii - Domestic Aviation	*19.357*
Aviation : Domestic Air transport : Interstate - Jet Fuel > CH4 (Excluded)	0.011
Aviation : Domestic Air transport : Interstate - Jet Fuel > CO2 (Excluded)	19.160
Aviation : Domestic Air transport : Interstate - Jet Fuel > N2O (Excluded)	0.186
1A3d - Water-borne Navigation	25.06
1A3di - International Water-borne Navigation (International Bunkers)	*25.062*
Water-borne : International Marine Bunker Fuel - Distillate > CH4 (Excluded)	0.001
Water-borne : International Marine Bunker Fuel - Distillate > CO2 (Excluded)	0.352
Water-borne : International Marine Bunker Fuel - Distillate > N2O (Excluded)	0.003
Water-borne : International Marine Bunker Fuel - Residual Fuel Oil > CH4 (Excluded)	0.036
Water-borne : International Marine Bunker Fuel - Residual Fuel Oil > CO2 (Excluded)	24.487
Water-borne : International Marine Bunker Fuel - Residual Fuel Oil > N2O (Excluded)	0.184

Summary of Categories Excluded from the Inventory.

Gross California Emissions	**59.02**
Net California Emissions	**59.02**

Appendix B

Carbon Flux Table and Diagram

Emissions (MMTCO2)		
Category	**Data Source**	***1990***
Sinks		
Forest Land (Sinks)		-14.245
Forest Growth	*Winrock*	*-13.141*
Rangeland Growth	*Winrock*	*-1.104*
Sinks		**-14.245**
Emissions		
Forest Land (Emissions)		3.261
Forest/Rangeland Fires (Combustion & Decomposition)	*Winrock*	*2.032*
Development of Forest/Rangelands (Land Use Change)	*Winrock*	*0.021*
Forest/Rangeland Other Emissions (Unspecified)	*Winrock*	*1.208*
Slash Left Behind from Harvests (Decomposition)	Winrock	0.156
Fuel Wood from Harvests (Combustion)	Winrock	1.532
Composting of Wood Waste Materials (Decomposition)	CIWMB/USEPA	0.255
Wood Waste Dumps	CIWMB	0.000
Landfilled Wood Waste (Emissions)	ARB Model	2.350
Emissions		**7.555**
Net CO2 Flux		**-6.690**

Description

The net CO2 flux for the forest sector is estimated from summing CO2 removals from the atmosphere and CO2 emissions to the atmosphere on managed lands and the wood products pool. Removals of CO2 from the atmosphere occur as a result of vegetation growth. Emissions of CO2 to the atmosphere occur as a result of a variety of land use activities. These include emissions from oxidation of timber harvest slash, fuel wood, biomass consumed in wildfires, other disturbance (land use change or unspecified), or from the decomposition of landfilled or composted wood products consumed in the state. CO2 removals and emissions by urban forests will be included pending further data. This table focuses on forested lands, therefore CO2 removals and emissions on (non)woody crop lands are not reported, pending further study.

Data Sources

Winrock: CEC (2004). Baseline Greenhouse Gas Emissions for Forest, Range, and Agricultural Lands in California. CEC PIER final report CEC-500-04-069F. Annual average forest and range land CO2 removal and emission rates for period 1994 - 2000 in Table 1-21, CEC (2004) scaled to state-wide in CEC (2006): Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2004. Publication CEC-600-2006-013-SF. Emissions and removals are back-cast to 1990 from 1994 using 0.1707% per year forest land area trend from 1953 to 1994, from p. 14 in Shih (1998): The Land Base of California's Forests. Fire and Resource Assessment Program, California Dept. of Forestry and Fire Protection. Emissions and removals forecasted from 2000 using 4% forest land area decline predicted for 1997 to 2050 in the Pacific Coast Region, from p. 53 in: Area Changes for Forest Cover Types in the United States, 1952 to 1997, with projections to 2050. (2004) USDA Forest Service, Pacific Northwest Research Station, publication PNW-GTR-613.

CIWMB/USEPA: California Integrated Waste Management Board SWIS waste-in-place and landfill survey data, USEPA Harvested Wood Products use data provided by Kenneth Skog (Forest Products Laboratory, USDA Forest Service, Madison, WI), scaled to state based on population.

ARB Model: From IPCC Mathematically Exact First-Order Decay Model, with CIWMB SWIS waste-in-place and landfill survey data.

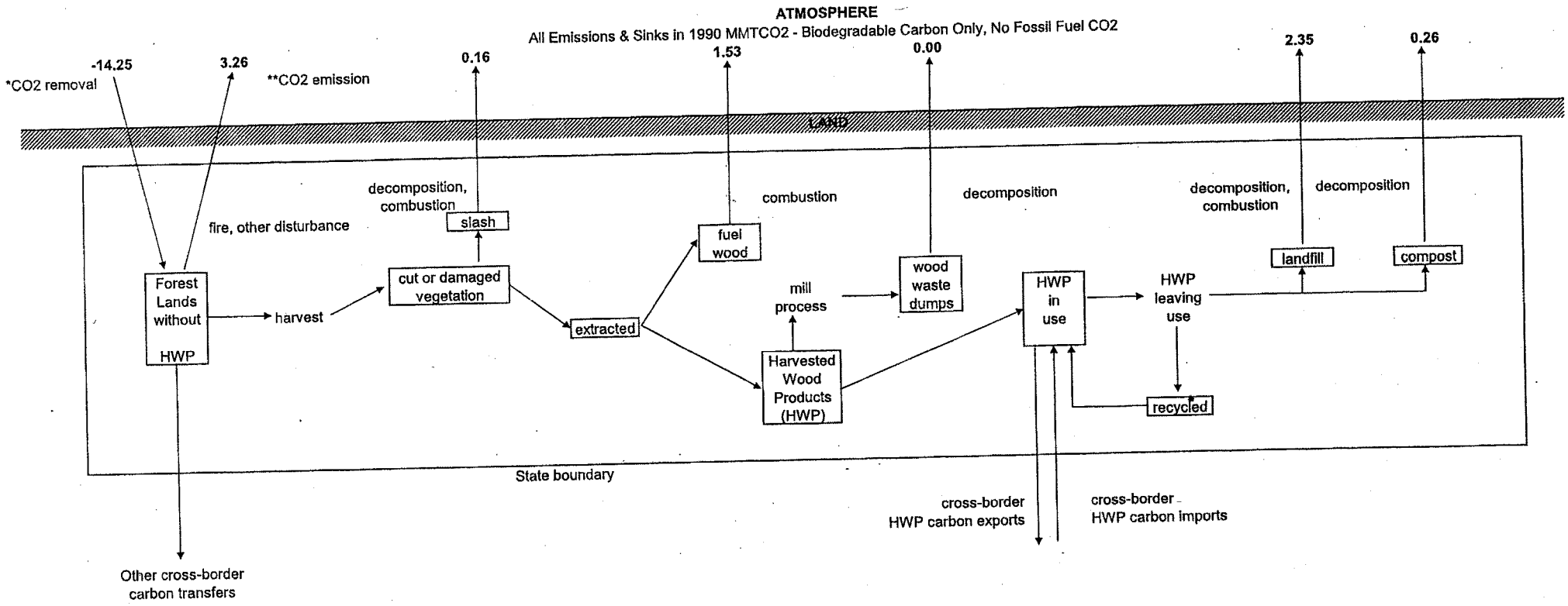
Diagram of the Atmospheric Flow Approach to forest and wood products carbon accounting for the forest sector of the state GHG inventory.

Adapted from:

1. Figure 12.A.2. System boundary of the Atmospheric Flow Approach.
   In: Chapter 12, Harvested Wood Products. Volume 4, Agriculture, Forestry, and Other Land Use (AFOLU). 2006 IPCC Guidelines for National Greenhouse Gas Inventories. IPCC National Greenhouse Gas Inventories Programme.

2. Figure 1-6. Flow diagram illustrating the various destinations of pre-harvest carbon after commercial harvest.
   In: Baseline Greenhouse Gas Emissions for Forest, Range, and Agricultural Lands in California. (2004) California Energy Commission PIER final report 500-04-069F.

1990 Net CO2 Flux (MMTCO2) = Emissions + Sinks: 7.55 + -14.25 = -6.69



*CO2 removal from the atmosphere includes vegetation growth in Forests and wooded Range Land.
**Land Use Change & Forestry CO2 emissions to the atmosphere includes emissions from: Forest and Range land fires, Forest and Range land use change (development) and other unspecified disturbance, decomposition/combustion of slash from tree harvest, fuel wood combustion, decomposition of wood mill waste and Harvested Wood Products in landfills and composting facilities.

The Atmospheric Flow Approach estimates fluxes of carbon to and from the atmosphere for the forest and wood products pools within the state boundary, and reports where and when emissions to the atmosphere and removals from the atmosphere occur. The state includes in its estimate of emissions/removals the removals of carbon from the atmosphere due to vegetation biomass growth, and the carbon release to the atmosphere from the oxidation of harvested wood products that are consumed in the state. (Adapted from: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4: Agriculture, Forestry, and Other Land Use.)

Appendix C

Global Warming Solutions Act of 2006

Assembly Bill No. 32

CHAPTER 488

An act to add Division 25.5 (commencing with Section 38500) to the Health and Safety Code, relating to air pollution.

[Approved by Governor September 27, 2006. Filed with Secretary of State September 27, 2006.]

LEGISLATIVE COUNSEL'S DIGEST

AB 32, Nunez. Air pollution: greenhouse gases: California Global Warming Solutions Act of 2006.

Under existing law, the State Air Resources Board (state board), the State Energy Resources Conservation and Development Commission (Energy Commission), and the California Climate Action Registry all have responsibilities with respect to the control of emissions of greenhouse gases, as defined, and the Secretary for Environmental Protection is required to coordinate emission reductions of greenhouse gases and climate change activity in state government.

This bill would require the state board to adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program, as specified. The bill would require the state board to adopt a statewide greenhouse gas emissions limit equivalent to the statewide greenhouse gas emissions levels in 1990 to be achieved by 2020, as specified. The bill would require the state board to adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions, as specified. The bill would authorize the state board to adopt market-based compliance mechanisms, as defined, meeting specified requirements. The bill would require the state board to monitor compliance with and enforce any rule, regulation, order, emission limitation, emissions reduction measure, or market-based compliance mechanism adopted by the state board, pursuant to specified provisions of existing law. The bill would authorize the state board to adopt a schedule of fees to be paid by regulated sources of greenhouse gas emissions, as specified.

Because the bill would require the state board to establish emissions limits and other requirements, the violation of which would be a crime, this bill would create a state-mandated local program.

The California Constitution requires the state to reimburse local agencies and school districts for certain costs mandated by the state. Statutory provisions establish procedures for making that reimbursement.

This bill would provide that no reimbursement is required by this act for a specified reason.

The people of the State of California do enact as follows:

SECTION 1. Division 25.5 (commencing with Section 38500) is added to the Health and Safety Code, to read:

DIVISION 25.5. CALIFORNIA GLOBAL WARMING SOLUTIONS ACT OF 2006

PART 1. GENERAL PROVISIONS

CHAPTER 1. TITLE OF DIVISION

38500. This division shall be known, and may be cited, as the California Global Warming Solutions Act of 2006.

CHAPTER 2. FINDINGS AND DECLARATIONS

38501. The Legislature finds and declares all of the following:

(a) Global warming poses a serious threat to the economic well-being, public health, natural resources, and the environment of California. The potential adverse impacts of global warming include the exacerbation of air quality problems, a reduction in the 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 marine ecosystems and the natural environment, and an increase in the incidences of infectious diseases, asthma, and other human health-related problems.

(b) Global warming will have detrimental effects on some of California's largest industries, including agriculture, wine, tourism, skiing, recreational and commercial fishing, and forestry. It will also increase the strain on electricity supplies necessary to meet the demand for summer air-conditioning in the hottest parts of the state.

(c) California has long been a national and international leader on energy conservation and environmental stewardship efforts, including the areas of air quality protections, energy efficiency requirements, renewable energy standards, natural resource conservation, and greenhouse gas emission standards for passenger vehicles. The program established by this division will continue this tradition of environmental leadership by placing California at the forefront of national and international efforts to reduce emissions of greenhouse gases.

(d) National and international actions are necessary to fully address the issue of global warming. However, action taken by California to reduce emissions of greenhouse gases will have far-reaching effects by encouraging other states, the federal government, and other countries to act.

(e) By exercising a global leadership role, California will also position its economy, technology centers, financial institutions, and businesses to benefit from national and international efforts to reduce emissions of greenhouse gases. More importantly, investing in the development of innovative and pioneering technologies will assist California in achieving the 2020 statewide limit on emissions of greenhouse gases established by this division and will provide an opportunity for the state to take a global economic and technological leadership role in reducing emissions of greenhouse gases.

(f) It is the intent of the Legislature that the State Air Resources Board coordinate with state agencies, as well as consult with the environmental justice community, industry sectors, business groups, academic institutions, environmental organizations, and other stakeholders in implementing this division.

(g) It is the intent of the Legislature that the State Air Resources Board consult with the Public Utilities Commission in the development of emissions reduction measures, including limits on emissions of greenhouse gases applied to electricity and natural gas providers regulated by the Public Utilities Commission in order to ensure that electricity and natural gas providers are not required to meet duplicative or inconsistent regulatory requirements.

(h) It is the intent of the Legislature that the State Air Resources Board design emissions reduction measures to meet the statewide emissions limits for greenhouse gases established pursuant to this division in a manner that minimizes costs and maximizes benefits for California's economy, improves and modernizes California's energy infrastructure and maintains electric system reliability, maximizes additional environmental and economic co-benefits for California, and complements the state's efforts to improve air quality.

(i) It is the intent of the Legislature that the Climate Action Team established by the Governor to coordinate the efforts set forth under Executive Order S-3-05 continue its role in coordinating overall climate policy.

CHAPTER 3. DEFINITIONS

38505. For the purposes of this division, the following terms have the following meanings:

(a) "Allowance" means an authorization to emit, during a specified year, up to one ton of carbon dioxide equivalent.

(b) "Alternative compliance mechanism" means an action undertaken by a greenhouse gas emission source that achieves the equivalent reduction of greenhouse gas emissions over the same time period as a direct emission reduction, and that is approved by the state board. "Alternative compliance mechanism" includes, but is not limited to, a

flexible compliance schedule, alternative control technology, a process change, or a product substitution.

(c) "Carbon dioxide equivalent" means the amount of carbon dioxide by weight that would produce the same global warming impact as a given weight of another greenhouse gas, based on the best available science, including from the Intergovernmental Panel on Climate Change.

(d) "Cost-effective" or "cost-effectiveness" means the cost per unit of reduced emissions of greenhouse gases adjusted for its global warming potential.

(e) "Direct emission reduction" means a greenhouse gas emission reduction action made by a greenhouse gas emission source at that source.

(f) "Emissions reduction measure" means programs, measures, standards, and alternative compliance mechanisms authorized pursuant to this division, applicable to sources or categories of sources, that are designed to reduce emissions of greenhouse gases.

(g) "Greenhouse gas" or "greenhouse gases" includes all of the following gases: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexaflouride.

(h) "Greenhouse gas emissions limit" means an authorization, during a specified year, to emit up to a level of greenhouse gases specified by the state board, expressed in tons of carbon dioxide equivalents.

(i) "Greenhouse gas emission source" or "source" means any source, or category of sources, of greenhouse gas emissions whose emissions are at a level of significance, as determined by the state board, that its participation in the program established under this division will enable the state board to effectively reduce greenhouse gas emissions and monitor compliance with the statewide greenhouse gas emissions limit.

(j) "Leakage" means a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state.

(k) "Market-based compliance mechanism" means either of the following:

(1) A system of market-based declining annual aggregate emissions limitations for sources or categories of sources that emit greenhouse gases.

(2) Greenhouse gas emissions exchanges, banking, credits, and other transactions, governed by rules and protocols established by the state board, that result in the same greenhouse gas emission reduction, over the same time period, as direct compliance with a greenhouse gas emission limit or emission reduction measure adopted by the state board pursuant to this division.

(*l*) "State board" means the State Air Resources Board.

(m) "Statewide greenhouse gas emissions" means the total annual emissions of greenhouse gases in the state, including all emissions of greenhouse gases from the generation of electricity delivered to and consumed in California, accounting for transmission and distribution line losses, whether the electricity is generated in state or imported. Statewide emissions shall be expressed in tons of carbon dioxide equivalents.

(n) "Statewide greenhouse gas emissions limit" or "statewide emissions limit" means the maximum allowable level of statewide greenhouse gas emissions in 2020, as determined by the state board pursuant to Part 3 (commencing with Section 38850).

CHAPTER 4. ROLE OF STATE BOARD

38510. The State Air Resources Board is the state agency charged with monitoring and regulating sources of emissions of greenhouse gases that cause global warming in order to reduce emissions of greenhouse gases.

PART 2. MANDATORY GREENHOUSE GAS EMISSIONS REPORTING

38530. (a) On or before January 1, 2008, the state board shall adopt regulations to require the reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program.

(b) The regulations shall do all of the following:

(1) Require the monitoring and annual reporting of greenhouse gas emissions from greenhouse gas emission sources beginning with the sources or categories of sources that contribute the most to statewide emissions.

(2) Account for greenhouse gas emissions from all electricity consumed in the state, including transmission and distribution line losses from electricity generated within the state or imported from outside the state. This requirement applies to all retail sellers of electricity, including load-serving entities as defined in subdivision (j) of Section 380 of the Public Utilities Code and local publicly owned electric utilities as defined in Section 9604 of the Public Utilities Code.

(3) Where appropriate and to the maximum extent feasible, incorporate the standards and protocols developed by the California Climate Action Registry, established pursuant to Chapter 6 (commencing with Section 42800) of Part 4 of Division 26. Entities that voluntarily participated in the California Climate Action Registry prior to December 31, 2006, and have developed a greenhouse gas emission reporting program, shall not be required to significantly alter their reporting or verification program except as necessary to ensure that reporting is complete and verifiable for the purposes of compliance with this division as determined by the state board.

(4) Ensure rigorous and consistent accounting of emissions, and provide reporting tools and formats to ensure collection of necessary data.

(5) Ensure that greenhouse gas emission sources maintain comprehensive records of all reported greenhouse gas emissions.

(c) The state board shall do both of the following:

(1) Periodically review and update its emission reporting requirements, as necessary.

(2) Review existing and proposed international, federal, and state greenhouse gas emission reporting programs and make reasonable efforts to promote consistency among the programs established pursuant to this part and other programs, and to streamline reporting requirements on greenhouse gas emission sources.

PART 3. STATEWIDE GREENHOUSE GAS EMISSIONS LIMIT

38550. By January 1, 2008, the state board shall, after one or more public workshops, with public notice, and an opportunity for all interested parties to comment, determine what the statewide greenhouse gas emissions level was in 1990, and approve in a public hearing, a statewide greenhouse gas emissions limit that is equivalent to that level, to be achieved by 2020. In order to ensure the most accurate determination feasible, the state board shall evaluate the best available scientific, technological, and economic information on greenhouse gas emissions to determine the 1990 level of greenhouse gas emissions.

38551. (a) The statewide greenhouse gas emissions limit shall remain in effect unless otherwise amended or repealed.

(b) It is the intent of the Legislature that the statewide greenhouse gas emissions limit continue in existence and be used to maintain and continue reductions in emissions of greenhouse gases beyond 2020.

(c) The state board shall make recommendations to the Governor and the Legislature on how to continue reductions of greenhouse gas emissions beyond 2020.

PART 4. GREENHOUSE GAS EMISSIONS REDUCTIONS

38560. 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 reductions from sources or categories of sources, subject to the criteria and schedules set forth in this part.

38560.5. (a) On or before June 30, 2007, the state board shall publish and make available to the public a list of discrete early action greenhouse gas emission reduction measures that can be implemented prior to the measures and limits adopted pursuant to Section 38562.

(b) On or before January 1, 2010, the state board shall adopt regulations to implement the measures identified on the list published pursuant to subdivision (a).

(c) The regulations adopted by the state board pursuant to this section shall achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from those sources or categories of

sources, in furtherance of achieving the statewide greenhouse gas emissions limit.

(d) The regulations adopted pursuant to this section shall be enforceable no later than January 1, 2010.

38561. (a) On or before January 1, 2009, the state board shall prepare and approve a scoping plan, as that term is understood by the state board, for achieving the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions from sources or categories of sources of greenhouse gases by 2020 under this division. The state board shall consult with all state agencies with jurisdiction over sources of greenhouse gases, including the Public Utilities Commission and the State Energy Resources Conservation and Development Commission, on all elements of its plan that pertain to energy related matters including, but not limited to, electrical generation, load based-standards or requirements, the provision of reliable and affordable electrical service, petroleum refining, and statewide fuel supplies to ensure the greenhouse gas emissions reduction activities to be adopted and implemented by the state board are complementary, nonduplicative, and can be implemented in an efficient and cost-effective manner.

(b) The plan shall identify and make recommendations on direct emission reduction measures, alternative compliance mechanisms, market-based compliance mechanisms, and potential monetary and nonmonetary incentives for sources and categories of sources that the state board finds are necessary or desirable to facilitate the achievement of the maximum feasible and cost-effective reductions of greenhouse gas emissions by 2020.

(c) In making the determinations required by subdivision (b), the state board shall consider all relevant information pertaining to greenhouse gas emissions reduction programs in other states, localities, and nations, including the northeastern states of the United States, Canada, and the European Union.

(d) The state board shall evaluate the total potential costs and total potential economic and noneconomic benefits of the plan for reducing greenhouse gases to California's economy, environment, and public health, using the best available economic models, emission estimation techniques, and other scientific methods.

(e) In developing its plan, the state board shall take into account the relative contribution of each source or source category to statewide greenhouse gas emissions, and the potential for adverse effects on small businesses, and shall recommend a de minimis threshold of greenhouse gas emissions below which emission reduction requirements will not apply.

(f) In developing its plan, the state board shall identify opportunities for emission reductions measures from all verifiable and enforceable voluntary actions, including, but not limited to, carbon sequestration projects and best management practices.

(g) The state board shall conduct a series of public workshops to give interested parties an opportunity to comment on the plan. The state board shall conduct a portion of these workshops in regions of the state that have the most significant exposure to air pollutants, including, but not limited to, communities with minority populations, communities with low-income populations, or both.

(h) The state board shall update its plan for achieving the maximum technologically feasible and cost-effective reductions of greenhouse gas emissions at least once every five years.

38562. (a) On or before January 1, 2011, the state board shall adopt greenhouse gas emission limits and emission reduction measures by regulation to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions in furtherance of achieving the statewide greenhouse gas emissions limit, to become operative beginning on January 1, 2012.

(b) In adopting regulations pursuant to this section and Part 5 (commencing with Section 38570), to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

(1) 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.

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

(3) 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.

(4) 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.

(5) Consider cost-effectiveness of these regulations.

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

(7) Minimize the administrative burden of implementing and complying with these regulations.

(8) Minimize leakage.

(9) Consider the significance of the contribution of each source or category of sources to statewide emissions of greenhouse gases.

(c) In furtherance of achieving the statewide greenhouse gas emissions limit, by January 1, 2011, the state board may adopt a regulation that establishes a system of market-based declining annual aggregate emission limits for sources or categories of sources that emit greenhouse gas emissions, applicable from January 1, 2012, to December 31, 2020, inclusive, that the state board determines will achieve the maximum

technologically feasible and cost-effective reductions in greenhouse gas emissions, in the aggregate, from those sources or categories of sources.

(d) Any regulation adopted by the state board pursuant to this part or Part 5 (commencing with Section 38570) shall ensure all of the following:

(1) The greenhouse gas emission reductions achieved are real, permanent, quantifiable, verifiable, and enforceable by the state board.

(2) For regulations pursuant to Part 5 (commencing with Section 38570), 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.

(3) 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.

(e) The state board shall rely upon the best available economic and scientific information and its assessment of existing and projected technological capabilities when adopting the regulations required by this section.

(f) The state board shall consult with the Public Utilities Commission in the development of the regulations as they affect electricity and natural gas providers in order to minimize duplicative or inconsistent regulatory requirements.

(g) After January 1, 2011, the state board may revise regulations adopted pursuant to this section and adopt additional regulations to further the provisions of this division.

38563. Nothing in this division restricts the state board from adopting greenhouse gas emission limits or emission reduction measures prior to January 1, 2011, imposing those limits or measures prior to January 1, 2012, or providing early reduction credit where appropriate.

38564. The state board shall consult with other states, and the federal government, and other nations to identify the most effective strategies and methods to reduce greenhouse gases, manage greenhouse gas control programs, and to facilitate the development of integrated and cost-effective regional, national, and international greenhouse gas reduction programs.

38565. The state board shall ensure that the greenhouse gas emission reduction rules, regulations, programs, mechanisms, and incentives under its jurisdiction, where applicable and to the extent feasible, direct public and private investment toward the most disadvantaged communities in California and provide an opportunity for small businesses, schools, affordable housing associations, and other community institutions to participate in and benefit from statewide efforts to reduce greenhouse gas emissions.

PART 5. MARKET-BASED COMPLIANCE MECHANISMS

38570. (a) The state board may include in the regulations adopted pursuant to Section 38562 the use of market-based compliance mechanisms to comply with the regulations.

(b) Prior to the inclusion of any market-based compliance mechanism in the regulations, to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit, the state board shall do all of the following:

(1) 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.

(2) Design any market-based compliance mechanism to prevent any increase in the emissions of toxic air contaminants or criteria air pollutants.

(3) Maximize additional environmental and economic benefits for California, as appropriate.

(c) The state board shall adopt regulations governing how market-based compliance mechanisms may be used by regulated entities subject to greenhouse gas emission limits and mandatory emission reporting requirements to achieve compliance with their greenhouse gas emissions limits.

38571. The state board shall adopt methodologies for the quantification of voluntary greenhouse gas emission reductions. The state board shall adopt regulations to verify and enforce any voluntary greenhouse gas emission reductions that are authorized by the state board for use to comply with greenhouse gas emission limits established by the state board. The adoption of methodologies is exempt from the rulemaking provisions of the Administrative Procedure Act (Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code).

38574. Nothing in this part or Part 4 (commencing with Section 38560) confers any authority on the state board to alter any programs administered by other state agencies for the reduction of greenhouse gas emissions.

PART 6. ENFORCEMENT

38580. (a) The state board shall monitor compliance with and enforce any rule, regulation, order, emission limitation, emissions reduction measure, or market-based compliance mechanism adopted by the state board pursuant to this division.

(b) (1) Any violation of any rule, regulation, order, emission limitation, emissions reduction measure, or other measure adopted by the state board pursuant to this division may be enjoined pursuant to Section 41513, and the violation is subject to those penalties set forth in Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26.

(2) Any violation of any rule, regulation, order, emission limitation, emissions reduction measure, or other measure adopted by the state board pursuant to this division shall be deemed to result in an emission of an air contaminant for the purposes of the penalty provisions of Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26.

(3) The state board may develop a method to convert a violation of any rule, regulation, order, emission limitation, or other emissions reduction measure adopted by the state board pursuant to this division into the number of days in violation, where appropriate, for the purposes of the penalty provisions of Article 3 (commencing with Section 42400) of Chapter 4 of Part 4 of, and Chapter 1.5 (commencing with Section 43025) of Part 5 of, Division 26.

(c) Section 42407 and subdivision (i) of Section 42410 shall not apply to this part.

PART 7. MISCELLANEOUS PROVISIONS

38590. If the regulations adopted pursuant to Section 43018.5 do not remain in effect, the state board shall implement alternative regulations to control mobile sources of greenhouse gas emissions to achieve equivalent or greater reductions.

38591. (a) The state board, by July 1, 2007, shall convene an environmental justice advisory committee, of at least three members, to advise it in developing the scoping plan pursuant to Section 38561 and any other pertinent matter in implementing this division. The advisory committee shall be comprised of representatives from communities in the state with the most significant exposure to air pollution, including, but not limited to, communities with minority populations or low-income populations, or both.

(b) The state board shall appoint the advisory committee members from nominations received from environmental justice organizations and community groups.

(c) The state board shall provide reasonable per diem for attendance at advisory committee meetings by advisory committee members from nonprofit organizations.

(d) The state board shall appoint an Economic and Technology Advancement Advisory Committee to advise the state board on activities that will facilitate investment in and implementation of technological research and development opportunities, including, but not limited to, identifying new technologies, research, demonstration projects, funding opportunities, developing state, national, and international partnerships and technology transfer opportunities, and identifying and assessing research and advanced technology investment and incentive opportunities that will assist in the reduction of greenhouse gas emissions. The committee may also advise the state board on state, regional, national, and

international economic and technological developments related to greenhouse gas emission reductions.

38592. (a) All state agencies shall consider and implement strategies to reduce their greenhouse gas emissions.

(b) Nothing in this division shall relieve any person, entity, or public agency of compliance with other applicable federal, state, or local laws or regulations, including state air and water quality requirements, and other requirements for protecting public health or the environment.

38593. (a) Nothing in this division affects the authority of the Public Utilities Commission.

(b) Nothing in this division affects the obligation of an electrical corporation to provide customers with safe and reliable electric service.

38594. Nothing in this division shall limit or expand the existing authority of any district, as defined in Section 39025.

38595. Nothing in this division shall preclude, prohibit, or restrict the construction of any new facility or the expansion of an existing facility subject to regulation under this division, if all applicable requirements are met and the facility is in compliance with regulations adopted pursuant to this division.

38596. The provisions of this division are severable. If any provision of this division or its application is held invalid, that invalidity shall not affect other provisions or applications that can be given effect without the invalid provision or application.

38597. The state board may adopt by regulation, after a public workshop, a schedule of fees to be paid by the sources of greenhouse gas emissions regulated pursuant to this division, consistent with Section 57001. The revenues collected pursuant to this section, shall be deposited into the Air Pollution Control Fund and are available upon appropriation, by the Legislature, for purposes of carrying out this division.

38598. (a) Nothing in this division shall limit the existing authority of a state entity to adopt and implement greenhouse gas emissions reduction measures.

(b) Nothing in this division shall relieve any state entity of its legal obligations to comply with existing law or regulation.

38599. (a) In the event of extraordinary circumstances, catastrophic events, or threat of significant economic harm, the Governor may adjust the applicable deadlines for individual regulations, or for the state in the aggregate, to the earliest feasible date after that deadline.

(b) The adjustment period may not exceed one year unless the Governor makes an additional adjustment pursuant to subdivision (a).

(c) Nothing in this section affects the powers and duties established in the California Emergency Services Act (Chapter 7 (commencing with Section 8550) of Division 1 of Title 2 of the Government Code).

(d) The Governor shall, within 10 days of invoking subdivision (a), provide written notification to the Legislature of the action undertaken.

SEC. 2 No reimbursement is required by this act pursuant to Section 6 of Article XIII B of the California Constitution because the only costs that

may be incurred by a local agency or school district will be incurred because this act creates a new crime or infraction, eliminates a crime or infraction, or changes the penalty for a crime or infraction, within the meaning of Section 17556 of the Government Code, or changes the definition of a crime within the meaning of Section 6 of Article XIII B of the California Constitution.

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TITLE 13. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO ADOPT GASEOUS POLLUTANT MEASUREMENT ALLOWANCES FOR CALIFORNIA'S HEAVY-DUTY DIESEL IN-USE COMPLIANCE REGULATION

The Air Resources Board (ARB or the Board) will conduct a public hearing at the time and place noted below to consider adoption of amendments to California's heavy-duty diesel engine (HDDE) test procedures. The proposed amendments would modify the measurement allowances for the regulated gaseous pollutants during heavy-duty diesel in-use compliance testing, when using Portable Emissions Measurement Systems (PEMS). The proposed amendments are essentially identical to the modifications planned by the United States Environmental Protection Agency (U.S. EPA).

DATE: December 6, 2007

TIME: Air Resources Board
Auditorium

PLACE: 9530 Telstar Avenue
El Monte, California 91731

This meeting location may change. This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., December 6, 2007, and may continue at 8:30 a.m., December 7, 2007. This item may not be considered until December 7, 2007. Please consult the agenda for the meeting, which will be available at least 10 days before December 6, 2007, to determine the location and day on which this item will be considered.

If you have a disability-related accommodation need, please go to http://www.arb.ca.gov/html/ada/ada.htm for assistance or contact the ADA Coordinator at (916) 323-4916. If you are a person who needs assistance in a language other than English, please contact the Bilingual Coordinator at (916) 324-5049. TTY/TDD/Speech-to-Speech users may dial 7-1-1 for the California Relay Service.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Sections Affected: Proposed amendments to title 13, California Code of Regulations (CCR), 1956.8, and the following document incorporated by reference therein: "California Exhaust Emission Standards and Test Procedures for 2004 and Subsequent Model Heavy-Duty Diesel Engines and Vehicles," as last amended July 26, 2007.

Background: Health and Safety Code section 43104 directs ARB to adopt test procedures to ensure compliance with emission standards for new heavy-duty motor vehicles. In 2006, ARB adopted a new in-use compliance regulation and test procedures that allow for a more efficient and cost-effective test method to conduct in-

use compliance testing of HDDEs. This new testing method, called the manufacturer-run heavy-duty diesel in-use testing program, requires manufacturers to emissions test a set number of their certified engine families each year using PEMS installed on selected test vehicles. These test vehicles would be tested with PEMS when placed in normal revenue service. Because testing will be conducted in the field instead of an environmentally controlled laboratory, ARB, U.S. EPA, and the engine manufacturers agreed to determine a "measurement allowance" for each pollutant to account for any potential difference in measurement accuracy. The Southwest Research Institute (SwRI), in San Antonio, Texas was contracted to develop PEMS measurement allowances for gaseous emissions, under the direction of a measurement allowance steering committee (MASC) comprised of members from ARB, U.S. EPA and the engine manufacturers.

Proposed Action: SwRI has completed testing and published a MASC approved final report establishing appropriate measurement allowances for oxides of nitrogen, non-methane hydrocarbons and carbon monoxide. The measurement allowances will be used when conducting heavy duty diesel in-use compliance testing using PEMS. Staff is proposing that the Board adopt the measurement allowances recommended by SwRI.

COMPARABLE FEDERAL REGULATIONS

Staff is proposing amendments to adopt the measurement allowances used when conducting heavy duty diesel in-use compliance testing using PEMS. U.S. EPA is expected to adopt the same measurement allowances for its essentially identical heavy-duty in-use compliance testing program within the next six months.

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

The Board staff has prepared a Staff Report: Initial Statement of Reasons (ISOR) for the proposed regulatory action, which includes a summary of the environmental and economic impacts of the proposal. The report is entitled: "Staff Report: Initial Statement of Reasons for the Proposed Rulemaking – Public Hearing to Adopt Gaseous Pollutant Measurement Allowances For California's Heavy-Duty Diesel In-Use Compliance Regulation."

Copies of the ISOR and the full text of the proposed regulatory language, in underline and strikeout format to allow for comparison with the existing regulations, may be accessed on the ARB's web site listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, 1st Floor, Sacramento, CA 95814, (916) 322-2990 at least 45 days prior to the scheduled hearing on December 6, 2007.

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 web site listed below.

Inquiries concerning the substance of the proposed regulation may be directed to the designated agency contact persons: Mr. Stephan Lemieux, Manager, On-Road Heavy Duty Diesel Section, at (626) 450-6162 or slemieux@arb.ca.gov, or Mr. Dipak Bishnu, Air Resources Engineer, On-Road Heavy Duty Diesel Section, at (626) 575-6696 or dbishnu@arb.ca.gov.

Further, the agency representative and designated back-up contact persons to whom non-substantive inquiries concerning the proposed administrative action may be directed are Alexa Malik, Manager, Board Administration & Regulatory Coordination Unit, (916) 322-4011, or Amy Whiting, Regulations Coordinator, (916) 322-4011. 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 available on the ARB Internet site for this rulemaking at www.arb.ca.gov/regact/2007/hdiuc07/hdiuc07.htm.

COSTS TO PUBLIC AGENCIES AND TO BUSINESSES AND PERSONS AFFECTED

The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies, private persons and businesses in reasonable compliance with the proposed regulations are presented below.

Pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that the proposed regulatory action will not create costs or savings 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 cost or savings to state or local agencies. The proposed amendments do not affect state or local agencies.

In developing this regulatory proposal, the ARB staff evaluated the potential economic impacts on representative private persons and businesses. ARB is not aware of any cost impacts that a representative private person would necessarily incur in reasonable compliance with the proposed action. The proposed amendments will have economic impacts on the manufacturers of HDDEs, however these impacts are expected to be slight and absorbable.

The Executive Officer has made an initial determination that the proposed regulatory action will not have a significant statewide adverse economic impact directly affecting businesses, including the ability of California businesses to compete with businesses in other states, or on representative private persons. The amendments would apply to all manufacturers of HDDEs and make California requirements consistent with federal law. None of the manufacturers of HDDEs is located in California.

In accordance with Government Code section 11346.3, the Executive Officer has determined that the proposed regulatory action will 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. Any impact on businesses in California is expected to be slight and positive. A detailed assessment of the economic impacts of the proposed regulatory action can be found in the ISOR.

The Executive Officer has also determined, pursuant to title 1, California Code of Regulations, section 4, that the proposed regulatory action will not affect small businesses. There will be no incremental costs associated with staff's proposal in addition to those already needed to comply with the federal regulation. Any impact on businesses in California is expected to be slight, absorbable and positive.

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, 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.

SUBMITTAL OF COMMENTS

Interested members of the public may also present comments orally or in writing at the meeting, and in writing or by e-mail before the meeting. To be considered by the Board, written comments submissions not physically submitted at the meeting must be received **no later than 12:00 noon, December 5, 2007**, and 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

Facsimile submittal: (916) 322-3928

Please note that under the California Public Records Act (Government Code section 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 30 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 that authority granted in Health and Safety Code sections 39600, 39601, 43013, 43018, 43100, 43101, 43104, 43105, and 43806; and Vehicle Code section 28114. This action is proposed to implement, interpret and make specific Health and Safety Code sections 39002, 39003, 39500, 43000, 43013, 43018, 43100, 43101, 43102, 43104, 43106, 43202, 43204, 43206, 43210, 43211, 43212, 43213, and 43806; and Vehicle Code section 28114.

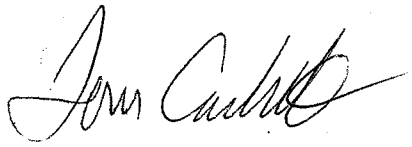
HEARING PROCEDURES

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 section 11340) of the Government Code.

Following the public hearing, the Board may adopt the regulatory language as originally proposed, or with nonsubstantial 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 such event 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 the ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, 1st Floor, Sacramento, CA 95814, (916) 322-2990.

CALIFORNIA AIR RESOURCES BOARD



Tom Cackette
Acting Executive Officer

Date: October 9, 2007

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 Web –site at www.arb.ca.gov.

California Environmental Protection Agency

Air Resources Board

STAFF REPORT: INITIAL STATEMENT OF REASONS

PUBLIC HEARING TO ADOPT GASEOUS POLLUTANT MEASUREMENT ALLOWANCES FOR CALIFORNIA'S HEAVY-DUTY DIESEL IN-USE COMPLIANCE REGULATION

Date of Release: October 19, 2007
Scheduled for Consideration: December 6-7, 2007

This report has been reviewed by the staff of the California 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.

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EXECUTIVE SUMMARY

In 2006, the Air Resources Board (ARB or Board) adopted a new in-use compliance regulation and test procedures (ARB (2006)). that allows for a more efficient and cost effective in-use compliance program for heavy-duty diesel engines (HDDE)(This new program, called the manufacturer-run heavy-duty diesel in-use testing program (HDIUT), requires the manufacturers to test a set number of their certified engine families each year using portable emission measurement systems (PEMS) installed on selected test vehicles. The HDIUT program evaluates HDDE compliance with the Not-to-Exceed (NTE) emission test limits that are part of the certification requirements for HDDE. The NTE test limits are not a prescribed test cycle but a wide range of engine operation that can be expected to occur during normal highway operation. An engine family that exceeds the in-use limits is subject to remedial action.

The adopted HDIUT program incorporated temporary measurement allowances when testing for compliance using PEMS. Measurement allowances are needed to account for measurement error associated with using PEMS in the field during over-the-road vehicle operation, instead of testing the engine in a controlled laboratory environment on an engine dynamometer. Prior to the adoption of this rule, an agreement was made between ARB, the United States Environmental Protection Agency (U.S. EPA), and the Engine Manufacturers Association (EMA), along with individual engine manufacturers, to fund a research program to establish better measurement allowances for each regulated pollutant (ARB, U.S. EPA, EMA (2005a)). A research program was developed through the guidance of a Measurement Allowance Steering Committee (MASC), comprised of members from ARB, U.S. EPA, and the engine manufacturers (ARB, U.S. EPA, EMA (2005b)). Testing, statistical modeling, and model validation of three different emission measurement methods have been completed by the main contractor, Southwest Research Institute, in San Antonio, Texas, with the help of the University of California's (at Riverside), Center for Environmental Research and Technology.

The intent of the research program was to develop a single set of measurement allowances based on the most stringent validated method that would replace the temporary allowances in the adopted rule. However, because there were some technical issues that delayed the program, only one measurement allowances method was validated during the initial modeling and analysis (SwRI (2007a)), (CE-CERT (2007)). The MASC recommended using the allowances based on this method for in-use testing of engines certified in 2007 through 2009 model years. The MASC also agreed to continue the work to validate all three emission measurement methods in order to obtain more representative measurement allowances for 2010 and later model years. SwRI conducted further analyses and modeling, resulting in the validation of all three measurement methods (SwRI (2007b)). The measurement allowances proposed by staff to the Board are given in Table ES-1, below:

Table ES-1 HDIUT Measurement Allowance Values by Model Year (g/bhp-hr)[1]

Pollutant	2007 – 2009 Model Year	2010 and Subsequent Model Year
NOx	0.45	0.15
NMHC	0.02	0.01
CO	0.50	0.25

1 Grams per brake-horsepower-hour

If adopted, these values would be added to the emissions measured by the PEMS to compensate for testing uncertainties when performing compliance testing in the field.

Economic and Air Quality Impacts

Staff's proposal would replace the current temporary measurement allowance values with values developed and validated through an extensive testing and modeling research program. Since the proposed allowances are smaller than the temporary allowances previously adopted, it is possible that engine manufacturers could be subject to additional remedial action. The impact on the engine manufacturers, and the impact on air quality, is expected to be slight. No impact on private businesses or persons is expected.

I. INTRODUCTION

The federal Clean Air Act grants California the authority to adopt and enforce rules to control mobile source emissions within California. In 2006, the Air Resources Board (ARB or Board) adopted a new in-use compliance regulation and test procedures (ARB (2006)) that allow for a more efficient and cost effective test method to conduct in-use compliance testing of heavy-duty diesel engines (HDDE). This new testing method, called the manufacturer-run heavy-duty diesel in-use testing program (HDIUT), requires the manufacturers to test a set number of their certified engine families each year using demonstrated and proven portable emission measurement systems (PEMS) that can be installed on selected test vehicles. These test vehicles are then tested with PEMS when they are placed in normal revenue service. An engine family that fails the in-use testing is subject to remedial action. The previous method to conduct in-use compliance testing required the removal of the test engine from the vehicle and testing it in a laboratory on an engine dynamometer, which was very costly and time consuming.

The adopted HDIUT program was developed through a coordinated effort among ARB, the United States Environmental Protection Agency (U.S. EPA), and the Engine Manufacturers Association (EMA) along with individual manufacturers (ARB, U.S. EPA, EMA (2003)). The success of this regulatory testing program depends on ensuring that the PEMS can correctly measure the exhaust emissions from heavy-duty diesel vehicles in the field. Compared to a controlled laboratory setting, these in-field instruments can potentially be influenced by uncontrollable factors such as ambient conditions and mechanical vibration. Thus, ARB, U.S. EPA, and the engine manufacturers agreed to determine a measurement allowance for each pollutant to account for any potential difference in measurement accuracy (ARB, U.S. EPA, EMA (2005a)). The staff's proposal, if adopted by the Board, would formally establish revised measurement allowances for gaseous pollutants, to be used in the HDIUT program. Measurement allowances for particulate matter are not part of staff's proposal. Such allowances are currently being evaluated and will be presented to the Board for consideration at a later date.

II. BACKGROUND

In January 2001, the U.S. EPA adopted new HDDE emission standards, along with modified Not-to-Exceed (NTE) and European Stationary Cycle (ESC) test requirements for 2007 and subsequent model year engines. In October 2001, the ARB harmonized with the federal program by adopting identical 2007 HDDE emission standards, and NTE and ESC requirements. The NTE limits are designed to apply under any conditions reasonably expected to occur during normal vehicle use. The test procedure for the NTE limits is different from all previous HDDE test procedures in that it is not based on any kind of test cycle, but instead allows testing at a wide range of engine and

ambient conditions that can occur in any normal vehicle operation. The NTE limits, as well as many other provisions of the 2007 HDDE rule, were intended to ensure that engines and vehicles designed to meet the original Federal Test Procedure (FTP) standards over the engine certification test cycle in the laboratory continued to effectively control emissions under all driving conditions reasonably expected to occur during normal vehicle use. The NTE protocol allows testing on an engine dynamometer, chassis dynamometer, or with PEMS during over-the-road operation. The maximum allowable NTE emissions, when averaged over a minimum time of 30 seconds, must not exceed an emission limit that is a multiple of the FTP standards.

In late 2001, EMA challenged ARB and U.S. EPA's adoption of the NTE limits. This led ARB, U.S. EPA, and EMA to start a lengthy and ultimately productive discussion on settling EMA's concerns with the NTE requirements and included an agreement among all parties to develop an effective in-use compliance program. Consequently, on June 3, 2003, ARB, the U.S. EPA, and EMA mutually developed a detailed outline (ARB, U.S. EPA, EMA, (2003)) for a future regulation that included a manufacturer-run HDIUT program for diesel-fueled engines and vehicles. Based on this collaborative effort, U.S. EPA adopted a manufacturer-run HDIUT program in June 2005, and in September 2006 ARB adopted an essentially identical such program (ARB (2006)). As part of this effort, ARB, the U.S. EPA, and EMA, agreed to develop an improved set of measurement allowances for each pollutant to account for any potential difference in measurement accuracy between PEMS and laboratory instruments.

III. SUMMARY OF PROPOSAL

A. APPLICABILITY

The proposed amendments to the HDIUT program would apply to the gaseous emissions of all 2007 and subsequent model year engine dynamometer certified diesel engines to be installed in vehicles with gross vehicle weight ratings greater than 8,500 pounds.

B. MEASUREMENT ALLOWANCES

1. OVERVIEW

Under an agreement among ARB, the U.S. EPA, and EMA, it was recognized that measurement allowances for each regulated pollutant would need to be developed before an enforceable HDIUT program could commence. The measurement allowance represents the incremental error between measuring emissions under controlled conditions in a laboratory with lab-grade equipment, and measuring emissions in the field using PEMS. Thus, in practical terms, a measurement allowance of "X" would be added to the NTE emission limit plus

the in-use compliance testing margin to calculate the NTE threshold value against which all emission results are compared for compliance determination.

In early 2005, ARB, U.S. EPA, and EMA agreed to use interim measurement allowance values of 0.50 grams per brake horsepower hour (g/bhp-hr) for oxides of nitrogen (NOx), 0.17 g/bhp-hr for non-methane hydrocarbon (NMHC), and 0.60 g/bhp-hr for carbon monoxide (CO) for pilot program testing. It was also agreed that these values would be revised once the measurement allowance values were determined through a coordinated research program.

To this end, ARB, U.S. EPA, and EMA formed a measurement allowance steering committee (MASC) that jointly financed a research contract with Southwest Research Institute (SwRI), in San Antonio, Texas. This program, completed in December, 2006, involved extensive testing and utilized a comprehensive statistical ("Monte Carlo") model to account for all the variables (e.g. ambient conditions, vibrations etc.) that could influence the results[1]. In addition to the variables, the model itself could be run in three different ways ("methods 1, 2, and 3")[2] based on specific assumptions and inputs. It was agreed by the MASC that the measurement allowance determined from using any of these methods would be acceptable provided the modeling results were validated[3]. It was also agreed that the numerically lowest validated measurement allowances would ultimately be used in the HDIUT program.

2. STAFF'S PROPOSAL

The initial Monte Carlo model results validated only one method (method 1). The initial validation work was completed in January 2007, and left very little time to proceed with further analysis without delaying the implementation of an enforceable HDIUT program for an additional year (from 2007 to 2008). Thus, ARB and U.S. EPA agreed to finalize and use the initial validated measurement allowances for the program. Specifically, it was agreed that these initial allowance values would be used for a minimum of three years, through 2009. The U.S. EPA and ARB agreed to continue to work with SwRI, and conduct additional testing and modeling analyses in an effort to validate all three measurement methods (including method 2 and 3).

On June 21, 2007, SwRI presented the results of the additional modeling work they had completed. This work resulted in validation of all three methods (SwRI (2007b)). After further discussion with EMA and the engine manufacturers, it

[1] Additional discussion on the determination of measurement allowances through laboratory testing, computer modeling, and over-the-road testing validation is provided in Appendix C and Reference SwRI (2007a)
[2] See Emission Calculations, 40 CFR Part 1065, Sections G and J and Reference U.S. EPA (2005c)
[3] Additional discussion on the "validation" methodology is provided in Appendix C and References SwRI (2007a), and CE-CERT (2007)

was agreed that the newly validated and more stringent measurement allowances should be used when conducting the HDIUT program on 2010 and subsequent model year HDDEs, while the initial method 1 validated measurement allowances should still be allowed for 2007 through 2009 model year HDDEs. Shown in Table 2 below are the proposed gaseous measurement allowances to be used in the HDIUT program.

Table 1 HDIUT Measurement Allowance Values by Model Year (g/bhp-hr)[1]

Pollutant	2007 – 2009 Model Year	2010 and Subsequent Model Year
NOx	0.45	0.15
NMHC	0.02	0.01
CO	0.50	0.25

1 Grams per brake horsepower-hour

IV. DIFFERENCES AND SIMILARITIES BETWEEN CALIFORNIA AND FEDERAL REGULATIONS

The U.S. EPA has not yet adopted staff's proposed measurement allowances, but intends to do so within the next six months. With regard to HDIUT in general, the U.S. EPA's and ARB's programs are essentially identical. Specifically, the engine family selection, test vehicle selection, testing protocol, test data collection and reporting, pass/fail criteria, etc., are all identical to the U.S. EPA's rule. The only element of ARB's program that arguably differs from U.S. EPA's program is ARB's authority to independently pursue remedial action on a non-complying engine family. This authority to enforce its own regulations is consistent with all ARB programs.

V. ECONOMIC IMPACTS

A. LEGAL REQUIREMENTS

Government Code Sections 11346.3 and 11346.5(a) require state agencies adopting and amending any administrative regulations to identify and assess the potential for adverse economic impacts on California businesses and individuals. State agencies are also required to estimate the cost or savings to any state or local agency and school districts. The assessment shall include a consideration of the impact of the proposed regulation on California jobs, business expansion,

elimination or creation, and the ability of California business to compete with business in other states.

State agencies are also 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 saving to the local agencies and the cost or saving in federal funding to the State.

B. AFFECTED BUSINESSES

Since the proposed allowances are smaller than the temporary allowances previously adopted, it is possible that engine manufacturers could be subject to additional remedial action. However, the impact on manufacturers is expected to be slight. No impact on private businesses or persons is expected. Also, there is no impact expected on PEMS manufacturers.

C. POTENTIAL COSTS TO ENGINE MANUFACTURERS

As stated above, the proposed allowances are smaller than the temporary allowances previously adopted, and thus it is possible that engine manufacturers could be subject to additional costs associated with remedial action. However, incremental costs on the engine manufacturers are expected to be slight and absorbable.

D. POTENTIAL IMPACTS ON BUSINESS COMPETITIVENESS

The proposed regulation is not expected to adversely impact the ability of California businesses to compete with similar businesses in other states.

E. POTENTIAL IMPACTS ON JOBS AND BUSINESS CREATION, ELIMINATION, OR EXPANSION

The proposed regulation is not expected to significantly impact the creation, elimination or expansion of jobs and businesses in California and is already covered by the adoption of the HDIUT regulation,

F. POTENTIAL COSTS TO LOCAL AND STATE AGENCIES

The proposed amendments to the Procedure will not create costs or savings, as defined in Government Code Section 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 non-

discretionary savings to local agencies. The staff has not encountered information that indicates that any of these impacts is to be expected.

No additional net costs for local and state agencies will be accrued as a result of the proposed regulation.

VI. ENVIRONMENTAL IMPACTS

A. AIR QUALITY IMPACTS

The implementation of the adopted HDIUT program will ensure that the expected emission benefits of 2007 HDDE standards are realized. The HDIUT program will encourage manufacturers to design and build robust engines and emission control systems to comply with the emission requirements during their useful life in order to avoid failure of in-use compliance testing which could ultimately lead to costly recalls or extended parts warranties. With regards to staff's proposal, there may be slight improvement in air quality due to the adoption of more stringent measurement allowances for the HDIUT program.

B. 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. The Board has established a framework for incorporating environmental justice into ARB's programs consistent with the directives of State law. The proposed regulation would benefit all Californians by ensuring that HDDEs comply with certification emission standards throughout their useful life. Communities located in proximity to ports, distribution centers, and other areas with high heavy-duty diesel vehicle activity would particularly benefit from the proposed regulation.

VII. REGULATORY ALTERNATIVES

No other alternatives to the proposed requirement have been evaluated since the proposed measurement allowances are necessary in order for the adopted HDIUT program to go forward.

VIII. REMAINING, NON-CONTROVERSIAL ISSUES

There are no specific issues, controversial or otherwise, related to this proposal or its potential impact on the implementation of the adopted HDIUT program.

IX. SUMMARY AND STAFF RECOMMENDATIONS

The proposed measurement allowances for gaseous pollutants are necessary for a successful implementation of California's heavy-duty diesel in-use compliance regulations. Specifically, the use of measurement allowances when conducting in-use testing of 2007 and newer HDDEs will allow for an effective and enforceable in-use compliance program for HDDEs and ensure that the emission benefits expected from the 2007 HDDE emission standards are realized.

Staff therefore recommends that the Board adopt the proposed measurement allowances for gaseous pollutants, as set forth in the amendments to section 1956.8, title 13, California Code of Regulations, and the incorporated "California Exhaust Emission Standards and Test Procedures for 2004 and Subsequent Model Heavy-Duty Diesel-Cycle Engines and Vehicles" (Appendices A and B).

X. REFERENCES

1. SwRI (2007a), Determination of PEMS Measurement Allowances for Gaseous Emissions Regulated Under the Heavy-Duty Diesel Engine In-Use Testing Program, March 2007

2. CE-CERT (2007), Measurement Allowance Project – On-Road Validation, March 2007

3. ARB (2006), Regulatory Documents for California's Heavy-Duty Diesel In-Use Compliance Regulation, Regulation adopted September 28, 2006 (http://www.arb.ca.gov/regact/inuse06/inuse06.htm)

4. ARB, U.S. EPA, EMA (2003), Outline of Regulatory Proposal (NPRM) for Manufacturer-Run In-Use Heavy-Duty Vehicle NTE Testing Program, May 9, 2003 (http://www.epa.gov/otaq/hd-hwy.htm)

5. ARB, U.S. EPA, EMA (2005a), Memorandum of Agreement, Program to Develop Emission Measurement Accuracy Margins for Heavy-Duty In-Use Testing, May 2005 (http://www.epa.gov/otaq/hd-hwy.htm)

6. ARB, U.S. EPA, EMA (2005b), Test Plan to Determine PEMS Measurement Allowances for the Gaseous Emissions Regulated under the Manufacturer-Run Heavy-Duty Diesel Engine In-Use Testing Program, October 25, 2005 (http://www.epa.gov/otaq/hd-hwy.htm)

7. U.S. EPA (2005c). Test Procedures for Testing Highway and Nonroad Engines and Omnibus Technical Amendments, (Federal Register, Vol. 70, No. 133, PP 40420 – 40468, Wednesday, July 13, 2005) (http://www.epa.gov/otaq/hd-hwy.htm)

8. SwRI (2007b), Results of HDIUT Modeling Runs Using Revised Error Surfaces, Janet Buckingham and Robert L. Mason, June 21, 2007

APPENDIX A

PROPOSED REGULATION ORDER

Amend the following section of Title 13, California Code of Regulations, to read as set forth in the following pages:

§1956.8	Exhaust Emission Standards and Test Procedures for 1985 and Subsequent Model Year Heavy-Duty Engines and Vehicles

PROPOSED MODIFICATIONS

Set forth below are the proposed amendments to title 13, of the California Code of Regulations. Proposed amendments are shown in underline to indicate additions and ~~strikeout~~ to indicate deletions. Amendments to this document as adopted on March 22, 2007 as part of the "Rulemaking to Consider Amendments to California's Emission Warranty Information Reporting and Recall Regulations and Emission Test Procedures," are indicated by double underline to indicate additions and ~~double strikeout~~ to indicate deletions compared to the test procedures as amended on July 26, 2007.

§ 1956.8. Exhaust Emission Standards and Test Procedures - 1985 and Subsequent Model Heavy Diesel-Engine and Vehicles.

Introduction. [No change.]

Section (a). [No change.]

(b) *Test Procedures.* The test procedures for determining compliance with standards applicable to 1985 and subsequent model heavy-duty diesel engines and vehicles and the requirements for participation in the averaging, banking and trading programs, are set forth in the "California Exhaust Emission Standards and Test Procedures for 1985 through 2003 Model Heavy-Duty Diesel Engines and Vehicles," adopted April 8, 1985, as last amended December 12, 2002, the "California Exhaust Emission Standards and Test Procedures for 2004 and Subsequent Model Heavy-Duty Diesel Engines and Vehicles," adopted December 12, 2002, as last amended ~~July 26, 2007~~ ~~[insert date of amendment for this rulemaking]~~ [insert date of amendment for this rulemaking], and the "California Interim Certification Procedures for 2004 and Subsequent Model Hybrid-Electric Vehicles, in the Urban Bus and Heavy-Duty Vehicle Classes," adopted October 24, 2002, which are incorporated by reference herein.

Section (c) through (e). [No change.]

NOTE: Authority cited: Sections 39600, 39601, 43013, 43018, 43100, 43101, 43102, 43104, 43105 and 43806, Health and Safety Code; and Section 28114, Vehicle Code. Reference: Sections 39002, 39003, 39500, 43000, 43013, 43017, 43018, 43100, 43101, 43101.5, 43102, 43104, 43106, 43202, 43204, 43205.5, 43206, 43210, 43211, 43212, 43213, and 43806, Health and Safety Code; and Section 28114, Vehicle Code.

APPENDIX B

PROPOSED AMENDMENTS TO THE CALIFORNIA EXHAUST EMISSION STANDARDS AND TEST PROCEDURES FOR 2004 AND SUBSEQUENT MODEL HEAVY-DUTY DIESEL-CYCLE ENGINES AND VEHICLES

PROPOSED

State of California
AIR RESOURCES BOARD

CALIFORNIA EXHAUST EMISSION STANDARDS AND TEST PROCEDURES FOR 2004 AND SUBSEQUENT MODEL HEAVY-DUTY DIESEL ENGINES AND VEHICLES

Adopted:	December 12, 2002
Amended:	July 24, 2003
Amended:	September 1, 2006
Amended:	July 26, 2007
Amended:	[INSERT DATE OF AMENDMENT]
Amended:	(Insert date of finalized amendment)

NOTE: Proposed amendments in this document are printed in a style to indicate changes from existing provisions (July 26, 2007 amendments.) Amendments to this document as adopted on March 22, 2007 as part of the "Rulemaking to Consider Amendments to California's Emission Warranty Information Reporting and Recall Regulations and Emission Test Procedures," are indicated by double underline to indicate additions and ~~double strikeout~~ to indicate deletions compared to the test procedures as amended on July 26, 2007. All existing language is indicated by plain type. All additions to the existing language are indicated by underline. All deletions to the existing language are indicated by ~~strikeout~~. Only those portions of the existing language containing the proposed modifications are included. All other portions remain unchanged and are indicated by the symbol "* * * * *" for reference. A complete set of the test procedures, as amended on July 26, 2007, is available at http://www.arb.ca.gov/msprog/onroadhd/HDDTPs_Clean_rev_9-12-07.pdf.

CALIFORNIA EXHAUST EMISSION STANDARDS AND TEST PROCEDURES FOR 2004 AND SUBSEQUENT MODEL HEAVY-DUTY DIESEL ENGINES AND VEHICLES

The following provisions of Subparts A, I, -N, S, and T, _Part 86, and of Subparts A through K, Part 1065,_Title 40, Code of Federal Regulations, as adopted or amended by the U.S. Environmental Protection Agency on the date set forth next to the applicable section listed below, and only to the extent they pertain to the testing and compliance of exhaust emissions from heavy-duty diesel engines and vehicles, are adopted and incorporated herein by this reference as the "California Exhaust Emission Standards and Test Procedures for 2004 and Subsequent Model Heavy-Duty Diesel Engines and Vehicles," except as altered or replaced by the provisions set forth below.

PART 86 – CONTROL OF EMISSIONS FROM NEW AND IN-USE HIGHWAY VEHICLES AND ENGINES

I. GENERAL PROVISIONS FOR CERTIFICATION AND IN-USE VERIFICATION OF EMISSIONS.

* * * * *

Subpart A - General Provisions for Emission Regulations for 1977 and Later Model Year New Light-Duty Vehicles, Light-Duty Trucks, and Heavy-Duty Engines, and for 1985 and Later Model Year New Gasoline-Fueled, Natural Gas-Fueled, Liquefied Petroleum Gas-Fueled and Methanol-Fueled Heavy-Duty Vehicles.

* * * * *

1. Definitions. [§86.xxx-2]

A. Federal Provisions.

1. **§86.004-2** January 18, 2001. [All federal definitions apply, except as otherwise noted below. Definitions specific to other requirements are contained in separate documents.]

B. California Provisions.

"Administrator" means the Executive Officer of the Air Resources Board.
"Certificate of Conformity" means "Executive Order" certifying vehicles for sale in California.
"Certification" means certification as defined in Section 39018 of the Health and Safety Code.

45-Day Notice Version
Date of Release: August 11, 2006
Board Hearing Date: September 28, 2006

"**EPA**" shall also mean Air Resources Board or Executive Officer of the Air Resources Board.
"EPA Enforcement Officer" means the Executive Officer or his delegate.
"Measurement allowance" means accuracy margin.
"Medium-duty engine" means a heavy-duty engine that is used to propel a medium-duty vehicle.
"Medium-duty vehicle" means 2004 through 2006 model year heavy-duty low-emission vehicle, ultra-low-emission vehicle, super-ultra-low-emission vehicle or zero-emission vehicle certified to the standards in title 13, CCR, section 1960.1(h)(2) having a manufacturer's gross vehicle weight rating of 14,000 pounds or less; and any 2004 and subsequent model heavy-duty low-emission, ultra-low-emission, super-ultra-low-emission or zero-emission vehicle certified to the standards in title 13, CCR section 1956.8(h), having a manufacturer's gross vehicle weight rating between 8,501 and 14,000 pounds.
"NTE standard" means NTE emission limit.
"**Warranty period**" [For guidance see title 13, CCR, §2036].

* * * * *

II. TEST PROCEDURES

Subpart I - Emission Regulations for New Diesel-Fueled Heavy-Duty Engines; Smoke Exhaust Test Procedure

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Subpart N - Emission Regulations for New Otto-Cycle and Diesel Heavy-Duty Engines; Gaseous and Particulate Exhaust Test Procedures

* * * * *

Subpart S – General Compliance Provisions for Control of Air Pollution From New and In-Use Light-Duty Vehicles, Light-Duty Trucks, and Complete Otto-Cycle Heavy-Duty Vehicles.

* * * * *

Subpart T - Manufacturer-Run In-Use Testing Program for Heavy-Duty Diesel Engines

86.1901 What testing requirements apply to my engines that have gone into service?

June 14, 2005. [No change.]

* * * * *

86.1912 How do I determine whether an engine meets the vehicle-pass criteria?
June 14, 2005. [No change, except as follows.]

* * * * *

(a)(3) Delete and replace with:

Measurement allowances for portable in-use equipment when testing is performed under the special provisions of §86.1930, depending on the pollutant, are as follows:

Pollutant	Measurement Allowances in grams/brake horsepower-hour for MY 2007-2009	Measurement Allowances in grams/brake horsepower-hour for MY 2010 and beyond
NMHC	0.02	0.01
CO	0.50	0.25
NOx	0.45	0.15
PM	0.10	0.10

* * * * *

Appendix I to Part 86 - Urban Dynamometer Schedules.

* * * * *

Appendix I to Subpart T – Sample Graphical Summary of NTE Emission Results

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PART 1065 – ENGINE-TESTING PROCEDURES.

Subpart A – Applicability and General Provisions

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Subpart B – Equipment Specifications

* * * * *

Subpart C – Measurement Instruments

* * * * *

Subpart D – Calibrations and Verifications

* * * * *

Subpart E – Engine Selection, Preparation, and Maintenance

* * * * *

Subpart F – Performing an Emission Test in the Laboratory

* * * * *

Subpart G – Calculations and Data Requirements

* * * * *

Subpart H – Engine Fluids, Test Fuels, Analytical Gases and Other Calibration Standards

* * * * *

Subpart I –Testing with Oxygenated Fuels

* * * * *

Subpart J – Field Testing and Portable Emission Measurement Systems

* * * * *

Subpart K – Definitions and Other Reference Information

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APPENDIX C

DETERMINATION OF MEASUREMENT ALLOWANCES THROUGH LABORATORY TESTING, COMPUTER MODELING, AND OVER-THE-ROAD TESTING VALIDATION

In 2006, the Air Resources Board (ARB or Board) adopted a new heavy-duty in-use testing (HDIUT) program. This compliance program incorporated temporary measurement allowances when testing for compliance using portable emission measurement systems (PEMS). Measurement allowances are needed to account for measurement error associated with using PEMS in the field during over-the-road vehicle operation, instead of testing the engine in a controlled laboratory environment on an engine dynamometer. Prior to the adoption of this program, an agreement was made between ARB, the United States Environmental Protection Agency (U.S. EPA), and the Engine Manufacturers Association (EMA), along with individual engine manufacturers, to fund a research program that establishes appropriate measurement allowances for each regulated pollutant. A research program was developed through the guidance of a Measurement Allowance Steering Committee (MASC), comprised of members from ARB, U.S. EPA, and the engine manufacturers. Testing, statistical modeling, and model validation of three different measurement allowance methods has been completed by the main contractor, Southwest Research Institute (SwRI), in San Antonio, Texas, with the help of the University of Riverside's Center for Environmental Research and Technology (CE-CERT).

The overall research program was a multi-faceted, complex research program that can be described with the following chronological steps:

1. Statistical model selection for measurement allowance generation

2. Testing for data generation using engine dynamometers and environmental chamber laboratories

3. Model simulation runs for measurement allowance determination

4. Initial model validation of measurement allowances

5. Additional model validation work and revised measurement allowances

1. Statistical Model Selection for Measurement Allowance Generation

A key element of the research program involved the use of a comprehensive and rigorous statistical modeling method to generate measurement allowances. A direct approach could have been to test PEMS against some kind of mobile laboratory reference, on a large number of vehicles, and quantify measurement errors directly. An example of this would be the mobile emissions laboratory used by CE-CERT. However, this approach would have been prohibitively expensive and time consuming. Also, it was felt that the desired laboratory reference point for error comparison was certification testing, normally conducted on an engine dynamometer in a laboratory. Since it was not feasible to conduct enough representative experiments to directly quantify

measurement allowances, the MASC recommended a methodology that involved the use of a statistical model for the determination of potential measurement errors. In this approach MASC would define all the sources of PEMS measurement errors, based on existing in-use testing expertise and the understanding of how the PEMS functions. It was then agreed that each of these errors would be quantified using a series of controlled laboratory experiments, each designed to isolate errors related to a single error source.

The heavy-duty diesel engine (HDDE) exhaust emission standard is expressed in terms of grams per brake horsepower-hour (g/bhp-hr). To measure exhaust in terms of g/bhp-hr, three separate inputs are needed. These include pollutant concentration in the exhaust, total engine exhaust flow rate, and the horsepower of the engine. There is the potential for measurement errors when these parameters are measured using PEMS, compared to the same measurements made by laboratory instruments. Because PEMS are exposed to an open and uncontrolled environment, these errors are introduced from variations of temperature, humidity, road vibration, and other factors. Potential errors are also introduced when instantaneous torque or fuel rate information is provided (or "broadcasted") to the PEMS by the engine's on-board computer. Thus, numerous experiments were conducted at SwRI to account for, and quantify, the margin of errors associated with all these variables.

The margin of errors were then programmed into a computer model, called the "Monte Carlo" model that employed statistical random sampling methods to simulate the combined effects of all sources of error on the final measured brake-specific emission value. For further details on the Monte Carlo model development, data simulation, and measurement error determination see SwRI Report, Determination of PEMS Measurement Allowances for Gaseous Emissions Regulated under the Heavy-Duty Diesel Engine In-Use Testing Program, March 2007, (SwRI (2007a)).

2. Testing for Data Generation Using Engine Dynamometers and Environmental Chamber Laboratories

Since manufacturers certify their engines on an engine dynamometer in a laboratory, it was essential to test candidate engines simultaneously with PEMS and an engine dynamometer. Certified 2005 and 2006 model year HDDEs were tested, one engine typically used in a heavy heavy-duty vehicle with a gross vehicle weight rating (GVWR) of over 33,000 pounds, one typically used in a medium heavy-duty vehicle (GVWR between 19,501 to 33,000 pounds), and one typically used in a light heavy-duty vehicle (GVWR between 8,500 to 19,500 pounds). In order to simulate a post-2007 test environment, SwRI procured and installed diesel particulate filters for the three test engines.

The original intention of the program was to examine PEMS from more than one manufacturer. However, at the time of testing only one PEMS manufacturer, Sensors Incorporated, was able to supply commercially available PEMS for the program. Therefore, the measurement allowance values are based solely on PEMS measurements using the Sensors Inc. SEMTECH-DS. Multiple SEMTECH-DS units were used during the program, often in parallel with each other, in order to assess PEMS-to-PEMS variability. Late in the program, several Horiba OBS-2200 PEMS were incorporated into the program as time and resources allowed. However, all measurements made with the OBS-2200 units were used for informational purposes only, and thus were not used for the final measurement allowance determination.

Engine dynamometer laboratory tests were conducted to establish the error between the PEMS emission analyzers and flow-meters against laboratory grade instruments. This required auditing all the PEMS and laboratory equipment in advance to ensure that they were operating properly, according to 40 CFR Part 1065 Subpart D (U.S. EPA (2005 c)). The laboratory tests involved determining the PEMS measurement errors compared to the lab instruments for steady-state and transient Not-to-Exceed (NTE) events. Also quantified was the impact of the engine control module's (ECM) ability to derive torque and brake specific fuel consumption (BSFC) compared to measured values in the laboratory. The ability of the PEMS to measure exhaust flow using different flow meter installations was also observed.

Environmental chamber tests were conducted to expose the PEMS to a variety of environmental factors, namely electromagnetic interferences, atmospheric pressure, temperature, humidity, vibration, and ambient hydrocarbon levels. During these tests, PEMS sampled a series of reference gases, and errors quantifying the reference values were calculated. The tests were designed to mimic real-world environmental factors with magnitude and frequency adjusted to the real-world conditions.

All emission calculations for brake-specific emission values were done using three calculations methods, as per 40 CFR Part 1065 Subparts G and J. The three calculations methods are (1) torque-speed, (2) BSFC, and (3) fuel specific methodologies. All three calculations provide work-based or "brake-specific" mass emissions results in units of g/bhp-hr. The Monte Carlo model was run on a set of 195 pre-determined reference NTE test points.

3. Model Simulation Runs for Measurement Allowance Determination

The determination of a set of brake-specific measurement allowances was the final goal of the research program. The test plan for this program outlined a methodology by which all of the data from the model simulation runs would be collected and analyzed statistically, in order to generate a set of three potential measurement allowances for each pollutant, one for each of the three calculation methods. The test plan outlined a specific method by which the final (i.e., numerically lowest) set of validated allowances for NOx, NMHC, and CO would be chosen.

4. Initial Model Validation of Measurement Allowances

As discussed, the model generated a set (NOx, NMHC, and CO) of measurement allowances for each of the three calculation methods. As a final confirmation, these data sets needed to be validated against a data set generated through actual in-use field testing. This is because the model generated an incremental offset in comparison to a laboratory reference. Thus, a suitable in-use reference measurement was needed. The MASC recommended that the CE-CERT mobile emission laboratory would be an appropriate reference for validation of the model with over-the-road field testing.

In order to insure that the validation was not affected by some inherent bias between the SwRI reference laboratory and the CE-CERT mobile emission laboratory, a correlation exercise was also performed between the two laboratories prior to the start of on-road validation efforts. The mobile emission laboratory was brought to SwRI's laboratory, where side-by-side correlation testing was conducted. During these tests, exhaust from the same test engine was alternately routed to the measurement systems of both SwRI and the mobile emission laboratory. The generated data showed that correlation between the facilities was acceptable.

After the correlation exercise was completed, a test truck was supplied to CE-CERT by a participating engine manufacturer. In addition, one of the PEMS used for testing at SwRI was also delivered to CE-CERT. CE-CERT then conducted a series of on-road test runs over various driving routes in California, which were designed to take the test truck through a wide range of environmental and ambient conditions (altitude, temperature, humidity, etc.). During these tests, simultaneous measurements were made with both the PEMS and the mobile emission laboratory.

Because the mobile emission laboratory is not capable of measuring vehicle torque directly, additional testing was conducted at SwRI to account for potential errors associated with measuring torque and BSFC. This involved removal of the engine from the test truck used by CE-CERT, and installation of that engine in SwRI's dynamometer test cell.

A full description of the validation efforts, including the data analysis methodology and the results of validation for each pollutant by all three calculation methods is given in Section 6 of SwRI's final report (SwRI (2007)). Details of CE-CERT's on-road validation testing are provided in a separate report, titled Measurement Allowance Project-On-Road Validation, March 2007 (CE-CERT (2007)).

As mentioned, a set of measurement allowance values were determined for each calculation method. These are shown in Table 1. The

Table 2 NTE Thresholds (g/bhp-hr)

NOx	2.0
NMHC	0.21
CO	19.4

As shown in Table 1, the model result for NO_x did not validate for calculation method 2 and 3, while the CO results did not validate for any of the three calculation methods. The model result for NOx was validated only for calculation method 1, while model result for NMHC was validated for all three calculation methods. Note that 2007 model year and newer engines (likely to be evaluated in the HDIUT program) are likely to be several orders of magnitude below the CO NTE threshold, and therefore the lack of validation for CO is not deemed to be a significant issue.

With the validation of CO not considered critical for the purpose of the HDIUT program, only Method 1 contained validated values for the other pollutants. The additive measurement allowance value for NOx, 0.45 g/bhp-hr, is calculated using the NOx NTE threshold value, 2.0g/bhp-hr, multiplied by 0.223, the measurement allowance percentage indicated in Table 1. The same calculation can be used to derive the measurement allowance values for NMHC and CO, as shown below in Table 3. In February 2007, the MASC accepted these candidate measurement allowance values but agreed that they would only be temporary until (and if) additional testing/analysis allowed the validation of more representative measurement allowances using the other methods. As a result, and to provide some stability for the manufacturers, the MASC recommended that method 1 be used (Torque-Speed method) for the measurement allowances through the 2009 model year.

Table 3 Measurement Allowances for 2007 – 2009 Model Year

Pollutant	Measurement Allowance, g/bhp-hr	NTE Threshold, g/bhp-hr
NOx	0.45	2.0
NMHC	0.02	0.21
CO	0.50	19.4

5. Additional Model Validation Work and Revised Measurement Allowances

Additional analyses and modeling runs were performed at SwRI in an effort to validate the other measurement allowances methods (method 2 and 3). Specifically, the MASC agreed to further refine the model with modified assumptions and additional modeling runs.[2] The additional modeling analysis validated all three brake specific emission calculation methods (method 1, 2, and 3), resulting in method 2 (the BSFC method) validating to the lowest and most stringent measurement allowances, presented in Table 4 below.

The MASC agreed that these new measurement allowances should be used when conducting the HDIUT program, starting with 2010 and subsequent model year HDDEs. The MASC also agreed that manufacturers should be allowed to use any of the three measurement calculation methods so long as they use the most stringent measurement allowance values established by method 2. The establishment of new and more stringent measurement allowances was essential for having an effective compliance program, especially the measurement allowance for NOx emissions.

Table 4 Measurement Allowances for 2010 and Subsequent Model Year

Pollutant	Measurement Allowance, g/bhp-hr	NTE Threshold, g/bhp-hr
NOx	0.15	0.45 [1] - 0.65 [2]
NMHC	0.01	0.22
CO	0.25	19.63

1. NOx threshold value is 0.45 g/bhp-hr for 2012 and subsequent MY engines when the "in-use compliance margin" provision in the 2007 HDDE regulation expires.
2 NOx threshold value is 0.55 to 0.65 g/bhp-hr for 2007–2011 model year engines, depending on the vehicle's odometer readings when applying the in-use compliance margin provision established in the 2007 HDDE regulation.

[2] See Presentation on 'Results of HDIUT Modeling Runs Using Revised Error Surfaces,' (SwRI (2007b))

TITLES 13 AND 17. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER THE ADOPTION OF PROPOSED REGULATIONS TO REDUCE EMISSIONS FROM DIESEL AUXILIARY ENGINES ON OCEAN-GOING VESSELS WHILE AT BERTH AT A CALIFORNIA PORT

The Air Resources Board (the Board or ARB) will conduct a public hearing at the time and place noted below to consider adoption of regulations to reduce emissions of diesel particulate matter (PM) and oxides of nitrogen (NOx) from the use of diesel-fueled auxiliary engines aboard ocean-going ships while docked, or hotelled, at a California port. Auxiliary engines are run to power lighting, ventilation, pumps, communication, and other onboard equipment while a ship is docked at a berth. The proposed regulations would require some vessels to turn off their auxiliary engines; it is expected, but not required, that many of those vessels would then receive their electrical power from shore while at berth. The regulations will also reduce emissions of carbon dioxide (CO_2), a greenhouse gas that is responsible for much of the global climate change.

Any person who owns, operates, charters, rents, or leases any container ship, passenger ship, or refrigerated cargo ship that visits a California port, or any person who owns or operates a port or terminal located at a port where container, passenger, or refrigerated cargo ships visit, would be subject to and have responsibilities under this regulation. This notice summarizes the proposed regulations. The Staff Report and Technical Support Document present the regulation and information supporting the adoption of the regulation in greater detail.

DATE: December 6, 2007

TIME: 9:00 a.m.

PLACE: Air Resources Board
Auditorium
9530 Telstar Avenue
El Monte, California 91731

This meeting location may change. This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., December 6, 2007, and may continue at 8:30 a.m., December 7, 2007. This item may not be considered until December 7, 2007. Please consult the agenda for the meeting, which will be available at least 10 days before December 6, 2007, to determine the location and day on which this item will be considered.

For individuals with sensory disabilities, this document is available in Braille, large print, audiocassette or computer disk. Please contact ARB's Disability Coordinator at (916) 323-4916 by voice or through the California Relay Services at 711, to place your

request for disability services. If you are a person with limited English and would like to request interpreter services, please contact ARB's Bilingual Manager at (916) 323-7053.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Sections Affected: Proposed adoption of new section 2299.3, title 13, California Code

further reduce emissions from ocean-going vessels docked at California ports. Ships can be docked at a California port from several hours to several days.

Control of Criteria Air Pollutants

Health and Safety Code (HSC) sections 43013 and 43018 direct ARB to adopt standards and regulations that the Board has found to be necessary, cost-effective, and technologically feasible for various mobile source categories, including off-road diesel engines and equipment such as marine vessels, through the setting of emission control requirements. Specifically, HSC section 43013(b) directs ARB to adopt such standards and regulations for marine vessels to the extent permitted by federal law.

Control of Toxic Air Contaminants

The California Toxic Air Contaminant Identification and Control Program (Air Toxics Program), established under California law by Assembly Bill 1807 (Stats. 1983, ch. 1047) and set forth in HSC sections 39650 through 39675, requires ARB to identify and control air toxics in California. The identification phase of the Air Toxics Program requires ARB, with participation of other state agencies such as the Office of Environmental Health Hazard Assessment, to evaluate the health impacts of, and exposure to substances, and to identify those substances that pose the greatest health threat as toxic air contaminants (TACs). ARB's evaluation is made available to the public and is formally reviewed by the Scientific Review Panel (SRP) established under HSC section 39670. Following ARB's evaluation and the SRP's review, the Board may formally identify a TAC at a public hearing. Following identification, HSC sections 39658, 39665, and 39666 require ARB, with participation of the air pollution control and air quality management districts (districts), and in consultation with affected sources and interested parties, to prepare a report on the need and appropriate degree of regulation for that substance (a "needs assessment") and to adopt airborne toxic control measures (ATCMs).

In 1998, the Board identified diesel PM as a TAC with no Board-specified threshold exposure level. A needs assessment for diesel PM was conducted between 1998 and 2000, which resulted in ARB staff developing and the Board approving a Risk Reduction Plan to Reduce Particulate Matter Emissions from Diesel-Fueled Engines and Vehicles (Diesel RRP) in 2000. The Diesel RRP presented information that identified the available options for reducing diesel PM and recommended control measures to achieve further reductions. The scope of the Diesel RRP was broad, addressing all categories of engines, both mobile and stationary, and included control measures for off-road diesel engines, such as those covered by the proposed regulation. The ultimate goal of the Diesel RRP is to reduce California's diesel PM emissions and associated cancer risks from 2000 baseline levels by 85 percent by 2020. The proposed regulation would reduce diesel PM emissions and the local health impacts from ships docked in California's ports and would assist the Board with meeting the 2020 Diesel RRP goal.

Attainment of Ambient Air Quality Standards

The federal Clean Air Act (CAA) requires the U.S. Environmental Protection Agency (U.S. EPA) to establish National Ambient Air Quality Standards (National Standards) for pollutants considered harmful to public health, including fine particulate matter ($PM_{2.5}$) and ozone. Set to protect public health, the national standards are adopted based on a review of health studies by experts and a public process. Ambient $PM_{2.5}$ is associated with premature mortality, aggravation of respiratory and cardiovascular disease, asthma exacerbation, chronic and acute bronchitis and reductions in lung function. Ozone is a powerful oxidant. Exposure to ozone can result in reduced lung function, increased respiratory symptoms, increased airway hyper-reactivity, and increased airway inflammation. Exposure to ozone is also associated with premature death, hospitalization for cardiopulmonary causes, and emergency room visits for asthma.

Areas in the State that exceed the national standards are required by federal law to develop State Implementation Plans (SIPs) describing how they will attain the standards by certain deadlines. The NOx emission reductions are needed because NOx leads to formation in the atmosphere of both ozone and $PM_{2.5}$; diesel PM emission reductions are needed because diesel PM contributes to ambient concentrations of $PM_{2.5}$. At this time, the South Coast Air Basin is required to attain the $PM_{2.5}$ standard by 2015. U.S. EPA further requires that all necessary emission reductions be achieved one calendar year sooner – by 2014 – in recognition of the annual average form of the standard.

The ARB has adopted revisions to the ozone and $PM_{2.5}$ SIPs and, as part of that action, will request from U.S. EPA a reclassification of the Basin to "extreme" nonattainment for ozone, which will give the Basin until 2023 to attain the federal ozone standard. ARB will submit the SIPs to the U.S. EPA by the applicable due dates within the next year.

Air quality modeling indicates that significant reductions of NOx are crucial to help meet both these standards. At this time, the strategy to achieve attainment of the $PM_{2.5}$ standards in the South Coast Air Basin includes a 55 percent reduction in NOx emissions and a 15 percent reduction in direct $PM_{2.5}$ emissions from 2006 baseline levels. The NOx emission reductions from the proposed regulation would play an essential role in assisting the South Coast Air Basin with meeting its 2014 $PM_{2.5}$ deadline as well as its future ozone deadlines.

The federal CAA permits states to adopt more protective air quality standards if needed, and California has set standards for particulate matter and ozone that are more protective of public health than respective federal standards. The Bay Area, South Coast, and San Diego areas are nonattainment for the State standards for ozone and $PM_{2.5}$. Health and Safety Code section 40911 requires the local air districts to submit plans to the Board for attaining the State ambient air quality standards, and HSC section 40924 requires triennial updates of those plans. The NOx and $PM_{2.5}$ emission reductions from the proposed regulation will assist the local air districts in achieving attainment of the State ambient air quality standards.

Control of Emissions from Goods Movement-related Activities

In April 2006, the Board approved the *Emission Reduction Plan for the Ports and Goods Movement in California* (GMERP). The GMERP identifies strategies for reducing emissions created from the movement of goods through California ports and into other regions of the State. The GMERP is part of the broader Goods Movement Action Plan (GMAP) being jointly carried out by the California Environmental Protection Agency and the Business, Transportation, and Housing Agency. Phase I of the GMAP was released in September 2005 and highlighted the air pollution impacts of goods movement and the urgent need to mitigate localized health risk in affected communities. The final GMAP was released in January 2007 and includes a framework that identifies the key contributors to goods movement-related emissions.

The GMERP identifies numerous strategies for reducing emissions from all significant emission sources involved in goods movement, including ocean-going vessels, harbor craft, cargo handling equipment, locomotives, and trucks. The GMERP identifies several strategies for reducing emissions from ocean-going vessels. Specific to hotelling emissions, the GMERP establishes a goal of utilizing shore power for 20 percent of the ship visits to California ports by 2010, 60 percent of visits by 2015, and 80 percent of visits by 2020. The proposed regulation would represent a significant first step toward satisfying the GMERP goals by requiring specific vessel types to use shore power for 50 percent of a fleet's visits to a port by 2014 and 80 percent of visits by 2020. Furthermore, emission reductions would begin in 2010 for vessel owners or operators choosing an alternative emission control technology to reduce their hotelling emissions.

The California Global Warming Solutions Act of 2006

In June 2005, Governor Arnold Schwarzenegger signed Executive Order S-3-05, which established targets for reducing GHG emissions in California: roll back GHG emissions 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 Assembly Bill (AB) 32 (Stats. 2006, ch. 488), which established the 2020 GHG emission reduction goal in State law (set forth in HSC §38500 et seq.) and made the ARB responsible for monitoring and reducing GHG emissions. AB 32 requires the Board, by January 1, 2009, to design and adopt an overall plan to reduce GHG emissions to 1990 levels by 2020. The Board has until January 1, 2011, to adopt the necessary regulations to implement that plan. Implementation begins no later than January 1, 2012, and the emission reduction target must be fully achieved by January 1, 2020. AB 32 also required the Board to identify a list of discrete early action GHG reduction measures by June 30, 2007. AB 32 defines discrete early action measures as regulations that are to be adopted by the Board and be enforceable by January 1, 2010.

In April 2007, ARB staff released a report identifying 37 proposed early action items the Board could undertake to mitigate GHG emissions in California. Port electrification was identified as a GHG emission reduction measure in this report. In September 2007,

ARB staff recommended reclassifying port electrification (now called Green Ports) from an early action measure to a discrete early action measure. Staff's recommended reclassifications will be considered by the Board at its October 25, 2007 hearing. The proposed regulation, while reducing diesel PM and NOx emissions, would also result in significant reductions of CO_2 emissions as a co-benefit of requiring cleaner grid-supplied electrical generation for ocean-going vessels while docked. These CO_2 emission reductions will help California meet its 2020 greenhouse gas emission reduction goal.

Authority

The ARB has authority under California law to adopt the proposed regulations. Health and Safety Code sections 43013(b) and 43018 provide broad authority for ARB to adopt emission standards and other regulations to reduce emissions from new and in-use vehicular, nonvehicular and other mobile sources. Under HSC sections 43013(b) and 43018, ARB is directly authorized to adopt emission standards and other regulations for marine vessels, as expeditiously as possible and to the extent permitted by federal law, to meet State standards. The ARB is further mandated by California law under HSC section 39666 to adopt ATCMs for new and in-use nonvehicular sources, including marine vessels such as ocean-going vessels, for identified TACs such as diesel PM. As noted, ARB is also mandated under HSC section 38500 et seq. to reduce greenhouse gas emissions, which are emitted at significant levels by ships hotelling at California ports.

Emission Reductions and Public Health Benefits Projected

The proposed regulations are expected to significantly reduce emissions of diesel PM from at-berth ocean-going vessels. Diesel PM emission reductions are needed to reduce premature mortality, cancer risk, and other adverse impacts from exposure to this TAC. The proposal would help achieve the 2020 goal set forth in the 2000 Diesel RRP of reducing diesel PM by 85 percent from 2000 baseline levels and the 2015 and 2020 goals of the GMAP. In December 2005, the Board adopted an auxiliary engine fuel regulation that will provide significant emission reductions from auxiliary engines on ocean-going vessels. The proposed regulations are expected to provide additional significant emission reduction benefits. Staff projects that, by 2020, the proposed regulation would reduce hotelling diesel PM and NOx emissions from container ships, passenger ships, and refrigerated cargo ships by nearly 75 percent relative to levels expected to be emitted. These emission reductions will occur in areas at and near ports where environmental justice concerns are especially prevalent. In addition, hotelling CO_2 emissions are expected to be reduced by 136,000 to 269,000 metric tons in 2020, which will assist the State with meeting the AB 32 mandates for greenhouse gas reductions.

The proposed regulations would also reduce diesel PM and NOx emissions that contribute to exceedances throughout the State of ambient air quality standards for both

$PM_{2.5}$ and ozone. These reductions will assist California in its goal of achieving State and federal air quality standards.
Furthermore, in addition to reducing cancer impacts caused by diesel PM, the proposed regulation will provide a significant reduction in non-cancer health impacts, including premature death, due to reductions in directly-emitted PM and the secondary formation of PM from NOx

Staff Report and Further Information

As described in more detail below, ARB staff has prepared two documents as part of this rulemaking, a Staff Report: Initial Statement of Reasons (Staff Report) and a Technical Support Document. Together with the needs assessment (i.e., the Diesel RRP), these two documents serve as the report on the need and appropriate degree of regulation for at-berth ocean-going vessels auxiliary engines.

Description of the Proposed Regulatory Action

Under the approach proposed by staff, the Board would adopt a regulation, pursuant to its authority under HSC sections 38500 et seq., 43013 and 43018, which would apply to the emissions from diesel engines on ocean-going ships while docked at a California port (as defined in the proposal). The Board would also approve adoption of essentially identical provisions as an ATCM, pursuant to its authority under HSC section 39666, which would complement the regulation and provide maximum notice to the regulated community of the regulatory requirements on ocean-going vessels. These measures will hereinafter sometimes be referred to collectively as "the proposed regulations."

Applicability

The regulations would apply to any person who owns, operates, charters, rents, or leases any container ship, passenger ship, or refrigerated cargo ship that visits a California port, or any person who owns or operates a port or terminal located at a port where container, passenger, or refrigerated cargo(reefer) ships visit. These ports include Los Angeles, Long Beach, Oakland, San Diego, San Francisco, and Hueneme.

The regulations apply to both U.S.-flagged vessels and foreign-flagged vessels. Foreign-flagged vessels are vessels registered under the flag of a country other than the United States.

Exemptions

The proposed regulations contain general and specific exemptions. Under the general exemptions, vessels in "innocent passage"; vessels owned or operated by local, state, federal or foreign governments in government non-commercial service; steamships; and auxiliary engines using natural gas are exempt from the regulations in their entirety. A steamship is an ocean-going vessel whose primary propulsion and electrical power are provided by steam boilers. Further, there are particular exemptions from specified

portions of the regulations for emergency events and delays caused by federal agency inspections, as set forth in the proposal.

Limited Hours of Operation for Auxiliary Diesel Engines at Berth

The proposed regulations allows for two options to reduce hotelling emissions; ship operators can either shut down their auxiliary engines while in port (not including 3 or 5 permissible hours of total operation, as specified in the proposal), or they can reduce the emissions from those auxiliary engines by specified degrees while docked.

The "limited auxiliary engine operation" option in the proposed regulations requires that the operators of container ships, passenger ships, and reefers that visit California ports shut down their auxiliary engines for most of their stay while hotelling. Specifically, these auxiliary engines must be shut down for 50 percent of a fleet's total visits to a California port in 2014 and 80 percent of the fleet's total visits to a port in 2020. While auxiliary engines are shut down, the ship's onboard electrical requirements would need to be satisfied by some other source of power. The source of electrical power used instead of the auxiliary engines must be provided either by the grid or by another power source with specific emissions standards.

Fleets that do not make a minimum number of annual visits to a California port are exempt from the auxiliary engine limitations for that port. The engine shutdown requirement is applied when there are 25 or more total annual visits by a container vessel fleet or reefer vessel fleet to a port. For passenger vessel fleets, this threshold is five annual visits. However, regardless of the number of annual visits, the regulations require a vessel to use shore power if it is equipped to do so, and it visits a berth equipped to provide compatible shore power.

As noted, to provide for sufficient time to connect and disconnect electrical lines for shore power, the proposed regulations allow the auxiliary engines to operate for up to three hours during a visit, or five hours during a visit for vessels that lose power during the process of switching power from the vessel's auxiliary engines to shore power. This time period may be extended due to circumstances beyond the control of the vessel operators, such as emergency events or delays resulting from obligations imposed by federal agencies (for example, the Department of Homeland Security or the U.S. Coast Guard).

Emission Reduction Option

An alternative to the "limited auxiliary engine operation" approach is the "emissions reduction option"; operators choosing this option are required to reduce their auxiliary engine emissions at a port by specific amounts and by specific dates. The compliance dates vary based on the types of emission reduction techniques applied to the fleets. The emission reduction techniques that could be applied to a fleet include: 1) using selected vessels for grid-supplied power based on potential auxiliary engine emission reductions rather than fleet visit percentages; 2) using distributed generation equipment

to provide power to a vessel; 3) using alternative emission controls onboard a vessel or at the berth; and 4) using a combination of these techniques.

For option 1, the emission reduction targets are aligned with the limited engine operation approach: the NOx and PM emissions from the fleet's auxiliary engines at a port must be reduced by 50 percent from the baseline fleet emissions by 2014 and by 80 percent by 2020. For options 2 and 3, in which alternative control technologies are implemented, the NOx and PM emissions from the fleet's auxiliary engines at a port must be reduced by 20 percent from the baseline fleet emissions by 2010, 40 percent by 2012, 60 percent by 2014, and 80 percent by 2016. For option 4, in which a combination of approaches is implemented, NOx and PM emissions must be reduced by 20 percent from the baseline fleet emissions by 2012, 50 percent by 2014, and 80 percent by 2020.

The proposed regulations provide default values for making the emission reduction calculation, including default values for emission factors and power requirements, in lieu of more specific values. In addition, the proposal provides procedures for determining control factors and applicable emission testing procedures.

Sources of electrical power, other than the grid, that are used to comply with the emission reduction option would be subject to additional requirements. Before January 1, 2014, distributed generation equipment must satisfy the emission standards applicable to a newly manufactured spark-ignited off-road engine. By January 1, 2014, all distributed generation must satisfy a more stringent emission standard that is equivalent to a spark-ignited engine using Best Available Control Technology (BACT). Finally, the source of electrical power must emit no more CO_2 (a greenhouse gas) emissions than a combined-cycle gas turbine – the emissions level that the California Public Utilities Commission recommended for unspecified sources of power.

Recordkeeping and Reporting Requirements

The proposed regulations have reporting and recordkeeping requirements affecting the vessel owners and operators, terminals, and ports.

The reporting and recordkeeping requirements for vessel owners or operators depend upon the compliance option selected by the vessel owner or operator and terminal. The proposed regulations require a vessel fleet plan to be submitted to the Executive Officer of the ARB in the years prior to the fleet's regulatory compliance dates.

In addition to the vessel fleet plans, the proposal requires an annual statement of compliance to be submitted to the Executive Officer of the ARB certifying compliance with the regulatory requirements for the previous calendar year. As with the vessel fleet plans, the dates for the initial submittals depend upon the compliance option selected by the vessel owner or operator.

The recordkeeping and reporting requirements are simpler for the limited auxiliary engine use option because the vessel owner or operator choosing that option must track only those vessels that will comply with the 2014 and 2020 shore power requirements. The recordkeeping and reporting requirements for the emission reduction option are more significant because the vessel owner or operator choosing that option must track the emissions of each vessel in the fleet.

A terminal that receives more than 50 vessel visits in 2008 is required to submit a plan to ARB's Executive Officer by July 1, 2009, that identifies how the terminal will be upgraded to allow vessels to satisfy either the limited auxiliary engine operation option or the emissions reduction option. The terminal is also required to submit plan updates at a frequency dependant upon the control strategy selected by the vessel fleet owner or operator and the terminal.

The port is required to submit wharfinger data annually to ARB's Executive Officer, documenting when each vessel visits the port, the berth that the vessel visited, and the dates and times that the vessel was initially tied to the berth and subsequently released from the berth. In addition, the terminal operator is required to keep records of electricity usage for shore power and equipment breakdowns that affect a vessel's ability to comply with the limited auxiliary engine operation option or the emission reduction option.

Test Methods and Other Incorporated Documents

The proposal would incorporate by reference Parts 1, 2, and 4 of International Standard ISO 8178, as revised in 1996 by the International Organization for Standardization (ISO). This standard includes test methods for reciprocating internal combustion engines. Further, the proposal would incorporate by reference ISO 8754 (as adopted in 2003) for measuring the sulfur content of fuels used in auxiliary engines. The proposal would also incorporate by reference ARB's verification procedure requirements for diesel engine control measures as set forth in 13 CCR 2700 et seq. (June 2003), ARB's test method for NOx and CO_2 emissions as set forth in 17 CCR 94114 (July 1997), and the Bay Area Air Quality Management District's source test procedure for ammonia slip, ST-1B, dated January 1982. The proposal would also incorporate U.S. EPA's regulations for compression-ignition engines (40 CFR 94) and Annex VI of the 1973 International Convention for the Prevention of Pollution from Ships (as amended in 1978, also known as the MARPOL 73/78 Protocol); these would be incorporated to permit operators to submit engine test data measured pursuant to the federal regulation and international treaty, respectively.

Violations

The proposal specifies a violations provision that provides, among other things, that any violation of any part of the regulation would constitute a single, separate violation for each hour that the violation occurs. The exception to this would be for violations of the

recordkeeping and reporting requirements; a violation of those provisions would constitute a single, separate violation for each day that the violation occurs.

Severability

The proposed regulation states that if any part of the regulation is held to be invalid, the remainder of the regulation shall continue to be effective.

At the hearing, the Board may consider other elements that provide additional flexibility to affected owners and operators. In addition, the Board may consider revisions to the staff's proposal that result in requirements that are more or less stringent to those whom the proposed regulation is applicable.

COMPARABLE FEDERAL REGULATIONS

No federal standards or control requirements have been promulgated addressing emission reductions from at-berth ocean-going vessel auxiliary engines. Under CAA section 213, U.S. EPA is without authority to adopt in-use standards for nonroad engines, including marine engines.

California is the only governmental entity in the United States authorized by the CAA, in the first instance, to adopt emission requirements for in-use off-road engines. See *Engine Manufacturers Association v. U.S. EPA* (D.C. Cir. 1996) 88 F.3d 1075, 1089-1091. Under CAA section 209(e)(2), California may adopt and enforce emission standards and other requirements for off-road engines and equipment not conclusively preempted by section 209(e)(1), so long as California applies for and receives authorization from the Administrator of U.S. EPA. To obtain authorization, the Board must make a finding that the California adopted requirements will be, in the aggregate, at least as protective of public health and welfare as applicable federal standards. CAA section 209(e)(2)(A). The Administrator must grant a request for authorization from California unless he finds that ARB's protectiveness finding is arbitrary and capricious, that California does not need the standards to meet compelling and extraordinary conditions, or that the standards and accompanying enforcement procedures are not consistent with CAA section 209. *Ibid.*

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

As noted above, the Board staff has prepared two documents for the proposed regulatory action: a Staff Report, which includes a summary of the economic and environmental impacts of the proposal, and a Technical Support Document, which 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 – Regulations to Reduce Emissions from Diesel Auxiliary Engines on Ocean-Going Ships while At-Berth at a California Port." The Technical Support Document is entitled, "Technical Support Document: Technical Support for the Proposed Rulemaking – Regulations to

Reduce Emissions from Diesel Auxiliary Engines on Ocean-Going Ships while At-Berth at a California Port."

Copies of the Staff Report with the full text of the proposed regulatory language and the Technical Support Document may be accessed on the ARB's web site listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, 1st Floor, Sacramento, CA 95814, (916) 322-2990 at least 45 days prior to the scheduled hearing on December 6, 2007.

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 web site listed below.

Inquiries concerning the substance of the proposed regulation may be directed to the designated agency contact persons, Mike Waugh, Manager of the Project Assessment Section, at (916) 445-6018, or by email at mwaugh@arb.ca.gov, or Grant Chin, Staff Air Resources Engineer, at (916) 327-5602, or by email at gchin@arb.ca.gov.

Further, the agency representative and designated back-up contact persons to whom nonsubstantive inquiries concerning the proposed administrative action may be directed are Alexa Malik, Manager, Board Administration & Regulatory Coordination Unit, (916) 322-4011, and 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 Staff Report, Technical Support Document, and all subsequent regulatory documents, including the FSOR, when completed, are also available on the ARB Internet site for this rulemaking at www.arb.ca.gov/regact/2007/shorepwr07/shorepwr07.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 regulations are presented below.

While the proposal's engine shutdown requirement does not require vessels, ports, or terminals to install or modify any equipment, we anticipate vessel owners, operators, ports, and terminals will elect to install equipment that will allow vessels to use shore power while the auxiliary engines are shut down at berth. Assuming operators, ports, and terminals will make such investments, we estimate the total cost of regulatory compliance to be about $1.8 billion in 2006 expenditure-equivalent dollars (2006 dollars). This represents the total cost of the regulation if all money required to comply

with the proposed regulation were spent in 2006. This cost includes both capital and annual recurring costs. These costs would be spread over the years 2009 to 2020 for passenger ships and reefers and to 2030 for container ships. Two-thirds of this cost is the capital cost to add shore-power equipment to vessels. Annually, the costs are expected to vary from $15 million to $120 million. The total statewide annual costs to private business include recovery of capital expenditures, both aboard the ships and at the ports, and operating costs, which are labor costs and net energy costs, if any.

The total costs to a typical vessel operator complying with the proposed regulation, including capital costs, are estimated to be about $34 million. This cost would be distributed over a 22-year period, from 2009 to 2030. About 40 percent of the cost is associated with modifying additional vessels to replace vessels that have been re-deployed away from California ports. Annual costs would vary between $700,000 and $3 million per year, with the average cost of $1.7 million per year over this time period.

Similarly, the total costs to a typical terminal operator complying with the proposed regulation, including capital and ongoing costs are estimated to be about $17 million. About half of the cost is attributed to labor costs and the other half is for capital costs. This cost would be distributed over an 11-year period, from 2009 to 2020. Annual costs would vary between $500,000 and $1.7 million per year, with the average cost of $1.4 million per year over this time period. With 31 terminals and 35 vessel fleets affected by the proposed regulation, the cost to a typical business would be $26 million.

Vessel owners or operators, terminals, and ports would have additional recurring costs associated with recordkeeping and reporting. Reporting requirements begin July 1, 2009, and recordkeeping requirements begin January 1, 2010. For the vessel owner or operator, the costs associated with reporting and recordkeeping will vary between $600 and $12,000 annually. The higher cost for reporting and recordkeeping is based on the vessel owner or operator choosing to comply with the emission reduction option of the proposed regulation, and the lower end of the range represents the costs for vessel owners or operators complying with the limited auxiliary engine operation requirement. For the terminal operators and ports, the costs associated with reporting and recordkeeping are about $800 annually.

Staff estimates the cost-effectiveness of the proposed regulations, in terms of dollars per ton of PM emission reduction, to be is about $690,000 per ton if the total annualized cost is attributed solely to the PM reduction. Staff estimates the cost-effectiveness of the proposed regulation, in terms of dollars per ton of NOx emission reduction, to be about $12,800 per ton, if the total cost is attributed solely to the NOx emission reductions. Because the proposed regulation reduces significant amounts of both NOx and PM, staff also evaluated cost-effectiveness by attributing half the total annualized cost to the PM emission reductions and half to the NOx emission reductions. The resulting cost effectiveness values using that method are $6,400 per ton of NOx reduced and $345,000 per ton of PM reduced.

The Executive Officer has made an initial determination that the proposed regulatory action will not have a significant statewide adverse economic impact directly affecting businesses, including the ability of California businesses to compete with businesses in other states. The ARB staff has considered proposed alternatives that would lessen any adverse economic impact on businesses and invites you to submit proposals. Submissions may include the following approaches for consideration:

(i) 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) Use of performance standards rather than prescriptive standards.
(iv) Exemption or partial exemption from the regulatory requirements for businesses.

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 may 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. Businesses may be created in California that install electrical infrastructure at ports, sell emission control technologies that reduce NOx or PM from auxiliary engines, or provide distributed energy, due to the regulatory requirements.

The Executive Officer has also determined, pursuant to title 1, CCR, section 4, that the proposed regulatory action would not affect small businesses; due to the large capital and operating costs associated with vessel operations, we do not anticipate any small businesses would be affected by the proposal.

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 regulations 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 will not create costs or

savings 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, except as discussed below, or other nondiscretionary savings to state or local agencies.

The governmental agencies affected by the proposed regulation are the port authorities, which are branches of the local city governments. The ports affected by the proposed regulation include the ports of Hueneme, Long Beach, Los Angeles, Oakland, San Diego, and San Francisco. In addition, the cruise terminal at the Port of Long Beach is owned by the City of Long Beach. The total costs to be expended by the port authorities to add shore-power equipment to their facilities range from $4 million to $86 million. Staff anticipates that the port authorities would begin to make payments during fiscal years 2008/2009 and 2009/2010 for the necessary shore-power equipment to satisfy the 2014 shore-power requirements. The estimated fiscal costs for the ports range from $600,000 to $7.4 million for fiscal years 2007/2008 and 2009/2010.

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 in writing or by e-mail before the meeting. To be considered by the Board, written comments submissions not physically submitted at the meeting must be received **no later than 12:00 noon, Pacific Standard Time, December 5, 2007,** and 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
- Facsimile submittal: (916) 322-3928

Please note that under the California Public Records Act (Government Code section 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 30 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 38560, 38560.5, 39600, 39601, 39650, 39658, 39659, 39666, 41511, 43013, and 43018. This action is proposed to implement, interpret, or make specific Health and Safety Code sections 38560, 38560.5, 39000, 39001, 39515, 39516, 39650, 39658, 39659, 39666, 41510, 41511, 43013, 43016, and 43018; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, (1975) 14 Cal.3rd 411, 121 Cal.Rptr. 249.

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 section 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 the ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, 1st Floor, Sacramento, CA 95814, (916) 322-2990.

CALIFORNIA AIR RESOURCES BOARD

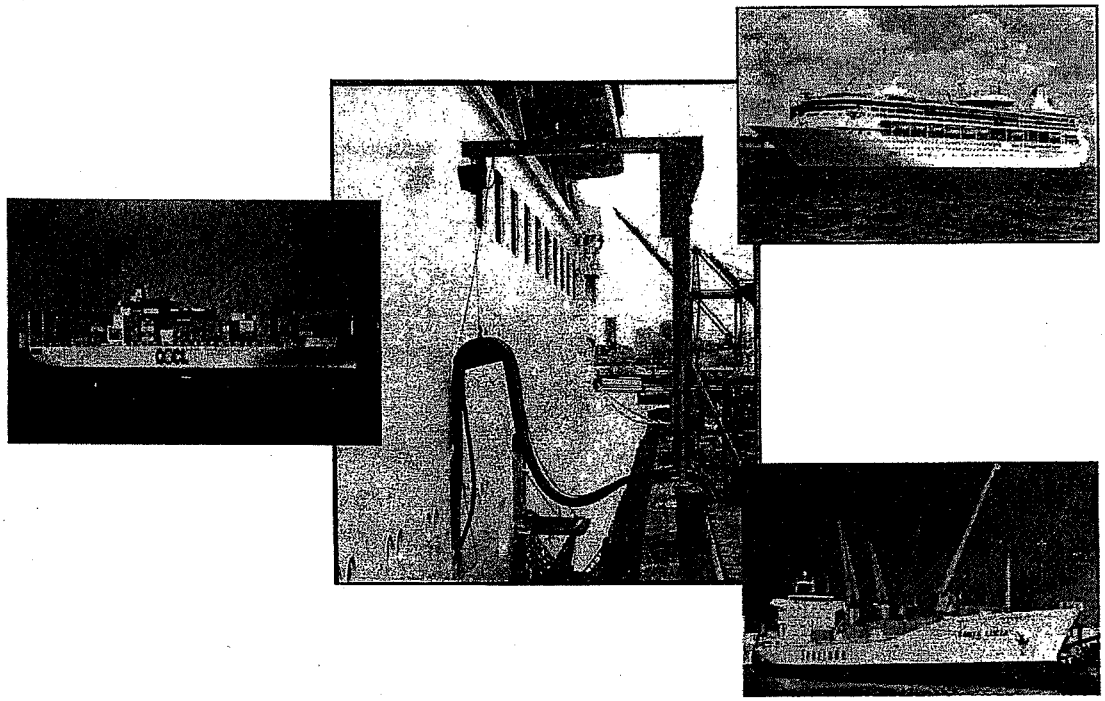
Tom Cackette
Acting Executive Officer

Date: October 9, 2007

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 the Proposed Rulemaking



Regulations to Reduce Emissions from Diesel Auxiliary Engines on Ocean-Going Vessels While At-Berth at a California Port

Stationary Source Division
Project Assessment Branch

October 2007

State of California
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR THE PROPOSED RULEMAKING

Public Hearing to Consider

ADOPTION OF PROPOSED REGULATIONS TO REDUCE EMISSIONS FROM DIESEL AUXILIARY ENGINES ON OCEAN-GOING VESSELS WHILE AT-BERTH AT A CALIFORNIA PORT

To be considered by the Air Resources Board on December 6 and 7, 2007, at:

Air Resources Board
Auditorium
9530 Telstar Avenue
El Monte, California 91731

Stationary Source Division
Robert Fletcher, Chief
Robert Barham, Ph.D., Assistant Chief
Project Assessment Branch
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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

REGULATIONS TO REDUCE EMISSIONS FROM DIESEL AUXILIARY ENGINES ON OCEAN-GOING VESSELS WHILE AT-BERTH AT A CALIFORNIA PORT

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Acknowledgements

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EXECUTIVE SUMMARY

The California Air Resources Board (ARB or Board) staff is proposing two essentially identical regulations to reduce diesel particulate matter (PM) and oxides of nitrogen (NOx) from diesel-fueled auxiliary engines used aboard ocean-going ships while docked or at-berth, at a California port. For the remainder of this report, the regulations will collectively be referred to as "the regulation." The proposed Regulations to Reduce Emissions from Diesel Auxiliary Engines on Ocean-Going Vessels While At Berth at a California Port (regulation) is part of ARB's ongoing effort to reduce PM and NOx emissions from diesel-fueled engines and vehicles and improve air quality associated with goods movement. A copy of the proposed regulation is provided in Appendix A of this report.

Auxiliary engines are run to power lighting, ventilation, pumps, communication, and other onboard equipment while a ship is docked at a berth, or "hotelled." The proposed regulation would require operators of vessels meeting specified criteria to turn off their auxiliary engines for most of their stay in port. We anticipate that such vessels would then receive their electrical power from the shore, or use an alternative, but equally effective, means of emission reductions. The process of shutting off engines and connecting to power on shore is sometimes referred to as "shore power" or "cold-ironing." The term "cold-ironing" is derived from the metal aboard the ships "going cold" when combustion equipment is shut down.

There are six major categories of ocean-going vessels that visit California ports: container ships, passenger ships, refrigerated cargo ships (reefers), bulk ships, tankers, and vehicle carriers. Over 2000 of these ocean-going vessels call at California ports each year. In 2006, about 1.8 tons per day (TPD) of diesel PM and 21.1 TPD of NOx were emitted from diesel-fueled auxiliary engines on ocean-going vessels while at-berth in California ports.

Staff is proposing to reduce hotelling emissions from three out of the six major vessel categories noted above; through a separate rulemaking, staff will address the hotelling emissions from the other three categories at a later date. This bifurcation of regulated vessel categories was based on information presented in an earlier ARB report, *Evaluation of Cold-ironing Ocean-Going Vessels at California Ports* (Evaluation Report), which was released as a draft in March 2006. The purpose of the Evaluation Report was to present an analysis of the feasibility and cost-effectiveness of requiring ships to shut off auxiliary engines, while in port and connect to power provided at the berth, as a potential emission control measure. The Evaluation Report was intended as a prelude to this rulemaking and was therefore never published as a final report. Nevertheless, the Evaluation Report provided a useful foundation on which this Staff Report was based.

From the Evaluation Report, staff found the most attractive ship candidates for shore power to be those ships that make frequent visits to a California port, spend a sufficient number of hours at berth, and have an ample power demand while hotelled. Accordingly, the proposal specifically targets hotelling emissions from ship categories that meet these criteria—container ships, passenger ships, and reefer ships—and the California ports where these ships frequently visit—the Ports of Los Angeles, Long Beach, Oakland, San Diego, San Francisco, and Hueneme.

As noted, staff will be proposing a separate rulemaking to reduce emissions from the other ship categories that were not considered as good candidates for shore power at this time—i.e., bulk ships, tankers, and vehicle carriers. Staff anticipates presenting to the Board a proposal covering those other ship categories in late 2008. We expect that at-berth emissions from tugboats operating at California ports will also be addressed at that time.

Diesel PM was identified as a toxic air contaminant in 1998. Long-term exposures to diesel PM increase the risk of developing lung cancer. Non-cancer health effects, including premature deaths and respiratory disease, are associated with exposure to directly emitted diesel PM and secondary diesel PM formed when NOx emissions from diesel engines react in the atmosphere to form nitrates. A recent ARB exposure study at the ports of Los Angeles and Long Beach shows that over two million people live in areas around the ports with predicted cancer risks of greater than 10 in a million due to hotelling emissions from ocean-going vessels. From that study and information developed for this rulemaking, staff estimates that about 61 premature deaths per year are attributable to current exposure to direct and secondary diesel PM from hotelling emissions.

The proposed regulation allows for two main options to reduce hotelling emissions. First, ship operators can shut down their auxiliary engines while in port, except for three or five permissible hours of total operation per visit ("limited engine use" option). Alternatively, operators can implement a fleet-based option to reduce the emissions from the auxiliary engines in the fleet by specified percentages while docked ("emissions reduction option").

The "limited engine use" option requires that the operators of container ships, passenger ships, and reefers that visit California ports shut down their auxiliary engines for most of their stay while hotelling. Auxiliary engines would be allowed to run for three or five hours per visit. Specifically, these auxiliary engines must be shut down for at least 50 percent of a fleet's total visits to a California port in 2014 and at least 80 percent of the fleet's total visits to a port in 2020. While auxiliary engines are shut down, the ship's onboard electrical needs must be satisfied by some other source of power, presumably the region's electrical grid.

An alternative compliance option is the "emissions reduction option," in which ship operators would be required to reduce their fleet's auxiliary engine emissions at a port by specific percentages and by specific dates. The specified percent reductions apply to the fleet's engines, rather than to individual engines. The compliance dates for this option vary based on the emission reduction technique applied to the fleets.

The emission reduction techniques that could be applied to a fleet include: 1) using selected vessels for grid-supplied power based on potential auxiliary engine emission reductions rather than fleet visit percentages; 2) using distributed generation equipment to provide power to a vessel; 3) using alternative emission controls onboard a vessel or located adjacent to the vessel; and 4) using a combination of these techniques.

Vessel owners or operators, terminals, and ports would also be subject to recordkeeping and reporting requirements.

Staff projects that the proposed regulation would reduce hotelling diesel PM and NOx emissions from container ships, passenger ships, and refrigerated cargo ships by nearly 50 percent relative to levels otherwise expected to be emitted in 2014, and 75 percent relative to levels otherwise expected to be emitted in 2020. These emission reductions will occur in areas at and near ports where community impacts are of most concern. These emission reductions would play an essential role in assisting the South Coast Air Basin with meeting its 2014 fine particulate matter ($PM_{2.5}$) deadline in its State Implementation Plan as well as its future ozone deadlines.

In addition, hotelling CO_2 emissions are expected to be reduced by 122,000 to 242,000 metric tons in 2020, which will assist the State with meeting the Assembly Bill (AB) 32 targets for greenhouse gas reductions.

The emission reductions from the proposed regulation would result in lower ambient PM levels and reduced exposure to diesel PM. Staff estimates that approximately 280 premature deaths statewide would be avoided by year 2020 from implementation of the proposed regulation. The estimated cost benefit of the avoided premature deaths and other health benefits due to the emission reductions are estimated to range from $1.3 to $1.9 billion.

The reduction in potential cancer risk was assessed based on the overall projected reduction in hotelling emissions from the proposed regulation. It was estimated that the population exposed to a risk of 10 in a million would be reduced by about 70 percent by 2020 due to these emission reductions. More importantly, all higher risk levels of greater than 100 in a million are eliminated due to implementation of the proposed regulation.

Staff estimates the statewide total regulatory costs for affected businesses and port authorities to comply with the proposed regulation to be approximately $1.8 billion, in 2006 dollars. This includes costs to comply with the regulation, which are primarily those incurred by vessel operators when they shut down their auxiliary engines at dock, as well as costs that are not strictly required to comply with the regulation but are nonetheless anticipated by ARB (e.g., installation of electrical infrastructure or distributed generation by shoreside entities).

Annually, the costs are expected to vary from $30 million to $137 million. The low end of the range represents a year when the only major capital expenditures are for retrofitting container ships due to repositioning, and the high end of the range represents a year when capital expenditures are being made for shoreside infrastructure and for retrofitting a considerable number of ships to meet the 2020 milestone. The total statewide annual costs to private business include recovery of capital expenditures, both aboard the ships and at the ports, and operating costs, which are labor costs and net energy costs. The Proposition 1B Bond program (Goods Movement Emission Reduction Program) potentially could provide funding for shore power projects. ARB is currently holding workshops for determining minimum requirements of shore power projects and other Prop 1B Bond projects.

The governmental agencies affected by the proposed regulation are the port authorities, which are branches of the local city governments. The ports affected by the proposed regulation are the Ports of Hueneme, Long Beach, Los Angeles, Oakland, San Diego, and San Francisco. Additionally, the cruise terminal at the Port of Long Beach is owned by the City of Long Beach. The costs to be expended by the port authorities to add shore-power equipment to their facilities ranges from $4 million to $86 million.

The overall cost-effectiveness of the regulation based on the regulatory costs and projected emission reductions is estimated to be $690,000 per ton if the total annualized cost is attributed solely to the PM reduction. Staff estimates the overall cost-effectiveness of the proposed regulation, in terms of dollars per ton of NOx emission reduction, to be about $12,800 per ton. This would be the cost-effectiveness if the total cost were attributed solely to the NOx emission reductions.

The cost-effectiveness for this regulation is consistent with those of other recent rulemakings, such as the Bus Fleet Rule, which was estimated to have a cost-effectiveness of nearly $68,000 per ton of NOx reduced, based on attributing all of the costs toward NOx emissions reductions. Because the proposed regulation reduces significant amounts of both NOx and PM, staff also evaluated cost-effectiveness by attributing half the total annualized cost to the PM emission reductions and half to the NOx emission reductions. The resulting cost-effectiveness values using that method are $6,400 per ton of NOx reduced and $345,000 per ton of PM reduced.

As noted, the proposal will reduce CO_2 emissions by 122,000 to 242,000 metric tons in 2020. The proposed regulation achieves these reductions automatically as a co-benefit of the diesel PM and NOx emission reductions. Because the proposed regulation is primarily a diesel PM and NOx control measure, and it will not mandate any additional requirements in order to reduce CO_2 emissions, there will be effectively zero costs involved in achieving these CO_2 emission reductions. Therefore, the cost-effectiveness for reducing CO_2 as a co-benefit of achieving the primary reductions in diesel PM and NOx emissions is essentially zero dollars per pound of CO_2 reduced.

INTRODUCTION

This Initial Statement of Reasons (Staff Report) presents an evaluation of the need to reduce emission from ocean-going vessels while at-berth. The evaluation looks at the corresponding health effects from such emissions, a summary of the proposed regulation (two essentially identical regulations collectively referred to hereinafter in the singular), and the projected emissions reductions along with the associated reduction in health risk. The Staff Report presents estimated costs for regulation compliance, for both industry and local governments, along with the alternative proposals considered. A copy of the proposed regulation is provided in Appendix A. The Technical Support Document, an addendum to the Staff Report, provides more detailed analyses of these subjects and supporting documentation for the proposal. The Technical Support Document is provided under separate cover.

Staff is proposing a regulation to reduce emissions of diesel particulate matter (PM) and nitrogen oxides (NOx) from diesel-fueled auxiliary engines used aboard ocean-going ships while docked at a California port. The proposal reduces emissions in a relatively straightforward way—by limiting the operation of auxiliary engines while the vessels are docked.

Auxiliary engines are run to power lighting, ventilation, pumps, communication, and other onboard equipment while a ship is docked at a berth, or "hotelled." The proposed regulation would require operators of vessels meeting specified criteria to turn off their auxiliary engines for most of their stay in port. We anticipate that such vessels would then receive their electrical power from shore, or would use an alternative, but equally effective, means of emissions reductions. This process of shutting off engines and connecting to power on shore is sometimes referred to as "shore power" or "cold-ironing." The term "cold-ironing" is derived from the metal aboard the ships "going cold" when combustion equipment is shut down.

The California Air Resources Board's (ARB or Board) mission is to protect public health, welfare, and ecological resources through the effective and efficient reduction of air pollutants, while recognizing and considering the effects on the economy of the State. The ARB's vision is that all individuals in California, especially children and the elderly, can live, work, and play in a healthful environment – free from harmful exposure to air pollution. To help achieve this, ARB has adopted numerous regulations to control emissions from many different sources, including diesel engines. Diesel engine exhaust is a significant health concern because it is a source of unhealthful air pollutants, including gaseous and particulate-phase toxic air contaminants (TAC), particulate matter (PM), oxides of nitrogen (NOx), carbon monoxide, and hydrocarbons.

In 1998, the Board identified diesel PM as a TAC with no Board-specified threshold exposure level, pursuant to Health and Safety Code (HSC) sections 39650 through 39675. A needs assessment for diesel PM was conducted between 1998 and 2000 pursuant to HSC sections 39658, 39665, and 39666. This resulted in ARB staff developing and the Board approving the *Risk Reduction Plan to Reduce Particulate Matter Emissions from Diesel-Fueled Engines and Vehicles* (Diesel RRP) in 2000. The Diesel RRP presented information on the available options for reducing diesel PM and recommended regulations to achieve these reductions. The Diesel RRP's scope was broad, addressing all categories of mobile and stationary engines. It included control measures for all off-road diesel sources, such as those covered by the proposed regulation. The ultimate goal of the Diesel RRP is to reduce, by 2020, California's diesel PM emissions and associated cancer risks by 85 percent from the 2000 levels. The proposed regulation would reduce diesel PM emissions and the local health impacts from ships docked in California's ports and would assist the Board with meeting the 2020 Diesel RRP goal.

In April 2006, the Board approved the *Emission Reduction Plan for the Ports and Goods Movement in California* (GMERP). The GMERP identifies strategies for reducing emissions created from the movement of goods through California ports and into other regions of the State. The GMERP is part of the broader Goods Movement Action Plan (GMAP) being jointly carried out by the California Environmental Protection Agency and the Business, Transportation, and Housing Agency. Phase I of the GMAP was released in September 2005 and highlighted the air pollution impacts of goods movement and the urgent need to mitigate localized health risk in affected communities. The final GMAP was released in January 2007 and includes a framework that identifies the key contributors to goods movement-related emissions.

The GMERP identifies numerous strategies for reducing emissions from all significant emission sources involved in goods movement, including ocean-going vessels, harbor craft, cargo handling equipment, locomotives, and trucks. The GMERP identifies several strategies for reducing emissions from ocean-going vessels. Specific to hotelling emissions, the GMERP establishes a goal of utilizing shore power for 20 percent of the ship visits to California ports by 2010, 60 percent of visits by 2015, and 80 percent of visits by 2020. The proposed regulation would represent a significant first step toward satisfying the GMERP goals by requiring specific vessel types to shut down their engines while docked. Shutting an engine down is a necessary condition for using shore power; the proposed regulation makes it possible for 50 percent of a fleet's visits to a port to be electrified by 2014, which rises to 80 percent of visits by 2020. Furthermore, emission reductions would begin in 2010 for vessel owners or operators choosing an alternative emission control technology to reduce their hotelling emissions.

The federal Clean Air Act (CAA) requires the United States Environmental Protection Agency (U.S. EPA) to establish National Ambient Air Quality Standards (national standards) for pollutants considered harmful to public health, including fine particulate matter ($PM_{2.5}$) and ozone. Set to protect public health, the national standards are adopted based on a review of health studies by experts and a public process. The South Coast Air Basin (Air Basin), which is home to the two largest ports in California, the Ports of Los Angeles and Long Beach, exceeds the national standards for both ozone and $PM_{2.5}$. Consequently, a State Implementation Plan (SIP) is required for the Air Basin that outlines how and when the region will attain the national standards. The U.S. EPA requires the Air Basin to meet the $PM_{2.5}$ standards by 2015, but the emission reductions must be in place by 2014.

Significant reductions of NOx are crucial to meet the federal standards. For example, at this time, the strategy to achieve attainment of the $PM_{2.5}$ standards in the South Coast Air Basin includes staff estimates that a 55 percent reduction in NOx emissions (secondary PM) from 2006 levels (i.e., a total reduction of hundreds of tons per day) and a 15 percent reduction in direct $PM_{2.5}$ emissions from 2006 baseline levels will be necessary for attainment of the $PM_{2.5}$ standards in the South Coast Air Basin. The proposed regulation would reduce hotelling NOx emissions from container ships, passenger ships, and refrigerated cargo ships by 50 percent relative to levels expected to be emitted in 2014 and nearly 75 percent relative to levels expected to be emitted in 2020. Consequently, the emission reductions from the proposed regulation would play an essential role in assisting the South Coast Air Basin with meeting its 2014 $PM_{2.5}$ deadline as well as its future ozone deadlines.

The federal Clean Air Act permits states to adopt more stringent air quality standards, and California has set standards for particulate matter and ozone that are more protective of public health than respective federal standards. The Bay Area, South Coast, and San Diego areas are nonattainment for the State standards for ozone and $PM_{2.5}$. Health and Safety Code (HSC) section 40911 requires the local air districts to submit plans to the Board for attaining the State ambient air quality standards, and HSC section 40924 requires triennial updates of those plans. The NOx and $PM_{2.5}$ emission reductions from the proposed regulation would also assist the local air districts in achieving attainment of the State ambient air quality standards.

In June 2005, Governor Arnold Schwarzenegger signed Executive Order S-3-05, which established targets for reducing greenhouse gas (GHG) emissions in California: roll back GHG emissions 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 Assembly Bill 32 (AB 32) (Stats. 2006, ch. 488), which established the 2020 GHG emission reduction goal in State law (HSC § 38500 et

seq.) and made the ARB responsible for monitoring and reducing GHG emissions.

AB 32 requires the Board, by January 1, 2009, to design and adopt an overall plan to reduce GHG emissions to 1990 levels by 2020. The Board has until January 1, 2011, to adopt the necessary regulations to implement that plan. Implementation begins no later than January 1, 2012, and the emission reduction target must be fully achieved by January 1, 2020. AB 32 also required the Board to identify a list of discrete early action GHG reduction measures by June 30, 2007. AB 32 defines discrete early action measures as regulations that are to be adopted by the Board and be enforceable by January 1, 2010.

In April 2007, ARB staff released a report identifying 37 proposed early action items the Board could undertake to mitigate GHG emissions in California. Port electrification was identified as a GHG emission reduction measure in this report. In September 2007, ARB staff recommended reclassifying port electrification (now called Green Ports) from an early action measure to a discrete early action measure. Staff's recommended reclassifications will be considered by the Board at its October 2007 hearing.

The proposed regulation, while primarily aimed at reducing diesel PM and NOx emissions, will also reduce CO_2 emissions as a co-benefit of requiring cleaner electrical generation for ocean-going vessels that "plug in" while docked. These CO_2 emission reductions will help California meet its 2020 greenhouse gas emission reduction goal.

2. DETERMINATION OF AFFECTED OCEAN-GOING VESSEL CATEGORIES

Staff is proposing to initially regulate hotelling emissions from three out of the six categories of ocean-going vessels that visit California ports and to address the hotelling emissions from the other three categories at a later date. This bifurcation was based on information presented in an earlier ARB report, *Evaluation of Cold-ironing Ocean-Going Vessels at California Ports* (Evaluation Report), which was released as a draft in March 2006. The purpose of the Evaluation Report was to present an analysis of the feasibility and cost-effectiveness of requiring ships to shut off auxiliary engines while in port and connect to power provided at the berth as a potential emission control measure. While not finalized, the results of the Evaluation Report nevertheless formed a good basis for ARB's further development of the proposed regulation.

In the Evaluation Report, ARB staff calculated, for screening purposes, the cost-effectiveness of shore power as an emission reduction strategy using three major sets of variables: ship categories, ship power loads, and pollutants reduced. ARB staff divided the ocean-going vessels visiting California ports in 2004 into

six categories: container ships, passenger ships, refrigerated cargo ships, tankers, bulk/cargo ships, and vehicle carriers. Cost-effectiveness values were calculated for each ship category. The cost-effectiveness values were based on the total cost of implementing cold-ironing— shore-side and ship-side— and the emission reductions expected from cold-ironing the ships.

For the screening analysis, staff analyzed three scenarios; 1) all ships being cold-ironed at all California ports; 2) cold-ironing ships that made at least three visits per year to a California port; 3) and cold-ironing ships that made at least six visits per year to a California port. ARB staff also calculated the cost-effectiveness values using three approaches for air pollutants reduced: (1) "all pollutants" emissions reductions (NOx, PM, volatile organic compounds [VOC], and oxides of sulfur [SOx]); (2) NOx emissions reductions only; and (3) PM emissions reductions only.

Based on the screening analysis noted above, the Evaluation Report concluded that the most attractive vessel candidates for cold-ironing are container ships, refrigerated cargo (reefer) ships, and passenger ships, and the most likely locations for cold-ironing in California are the Ports of Los Angeles, Long Beach, Oakland, San Diego, San Francisco, and Hueneme. The most attractive ship candidates were found to be those ships that make frequent visits to a California port, spend a sufficient number of hours at berth, and have an ample power demand while hotelled. These findings formed the foundation on which the proposed rulemaking was based.

Of the three remaining types of vessels that visit California, the Evaluation Report showed that it was not as cost-effective at this time to cold-iron bulk and general cargo ships and vehicle carriers, relative to container ships, passenger ships and reefers, because the former categories generally have a low number of repeat visits to any single port and lower power loads. Further, crude-oil tankers were found to have higher average cost-effectiveness values because there are only a handful of diesel-electric tankers that visit California, and only two are expected to visit frequently. Indeed, most crude-oil tankers use steam turbines to drive their cargo pumps. These cargo pumps represent the majority of the power needed by tankers when they are berthed. The rest of the ship's power needs are modest. Finally, product tankers make few visits to California ports, and their berthing times are short, making them a much less attractive candidate for cold-ironing.

The proposed regulation specifically addresses hotelling emission reduction requirements for categories of ships that were found at this time to be attractive candidates for shore power in the Evaluation Report—container ships, passenger ships, reefer ships— and the California ports where these ships frequently visit. As noted earlier, staff is proposing to develop separate requirements for other ship categories that were not considered to be good candidates at this time for

shore power -- bulk ships, tankers, and vehicle carriers—at a later date. Staff anticipates presenting proposed hotelling emission reduction requirements for these other ships to the Board in late 2008. We expect that at-berth emissions from tugboats operating at California ports will also be addressed at that time.

3. EMISSIONS INVENTORY

Hotelling emissions are associated with the use of diesel-fueled auxiliary engines on ocean-going ships to power the vessels' electrical systems while the ships are docked. These emissions are a function of how often the ship visits a California port, how long the ship is at berth, the emissions rate of the engines, and the typical operating load of the auxiliary engines while the ship is at berth.

ARB staff estimates that in 2006, the statewide hotelling emissions from approximately 2000 ocean-going vessels was 1.8 tons per day (TPD) of diesel PM emissions, and 21.1 TPD of NOx emissions. Table I presents hotelling emissions for the six major categories of ocean-going vessels that visit California ports—container ships, passenger ships, reefer ships, vessel carriers, bulk ships, and tankers. As can be seen in this table, hotelling emissions from the three affected ship categories, container ships, passenger ships, and reefer ships, represent over 80 percent of total statewide hotelling emissions.

Table 1: Estimated 2006 Hotelling Emissions by Ship Category

Ship Category	2006 Emissions, Tons/Day	
	NOx	PM
Container	13.8	1.1
Passenger	2.8	0.2
Reefers	0.9	0.1
Tanker	2.0	0.2
Bulk/General	1.0	0.1
Vehicle Carriers	0.6	0.1
Totals	21.1	1.8

The proposed regulation would affect ships visiting the Ports of Los Angeles and Long Beach (which, for the proposed regulation, would be considered one port), Oakland, San Diego, Hueneme, and San Francisco. To provide a perspective of

the shipping activities at these ports compared to all other ports in California, staff presents total hotelling emission by California port in Table 2.

Table 2: Estimated 2006 Hotelling Emissions by Port (Tons per Day)

Port	NOx	PM
Los Angeles/Long Beach	14.3	1.2
Oakland	2.6	0.2
San Diego	1.1	0.1
Hueneme	0.7	0.1
San Francisco	0.5	0.1
Other Ports	1.2	0.2
Total	21.1	1.8

As can be seen in this table, most of the shipping activities and hotelling emissions occur at the largest ports in California: Los Angeles and Long Beach followed by Oakland. The six ports affected by the proposed regulation account for over 90 percent of total hotelling emissions at California ports.

Staff developed growth factors for each ship category to project future hotelling emissions. In general, the growth in vessel hotelling emissions is directly proportional to the growth in vessel visits, ship size, berthing times, and, in the case of container ships, the number of refrigerated containers aboard.

Hotelling emissions from ocean-going ships are predicted to increase from 2006. Container ship and passenger ship emissions are expected to double by 2020. Reefer ship emissions are expected to decline at the Ports of Long Beach and Los Angeles, slightly increase at the Port of Hueneme, and triple at the Port of San Diego by 2020.

Table 3 presents projected 2014 and 2020 emission estimates for container ships, passenger ships, and reefer ships. In December 2005, the Board adopted an auxiliary engine fuel regulation that would limit the sulfur content of fuel used with auxiliary engines starting in 2007. At the time this staff report was published, the regulation had been challenged in federal district court and is undergoing appeal at the Ninth Circuit Court of Appeals. The future emission projections were based on the assumption that the auxiliary engine regulation would ultimately be upheld and the auxiliary engines would be operating on low-sulfur fuel.

Table 3: Projected 2014 and 2020 Emissions from Container Ships, Passenger Ships, and Reefer Ships

Ship Category	Projected 2014 Emissions Tons per Day		Projected 2020 Emissions Tons per Day	
	NOx	PM	NOx	PM
Container	21.4	0.38	30.8	0.55
Passenger	3.6	0.07	5.2	0.09
Reefer	1.0	0.02	1.3	0.02
Totals	26	0.47	37.3	0.67

4. HEALTH RISK

A. Cancer Risk

To provide a perspective on the potential cancer risk from exposure to hotelling emissions, staff used an existing analysis from 2004 of diesel PM emissions from port related activities (including hotelling emissions) at the Port of Los Angles and the Port of Long Beach. Staff then adjusted the results of that study to reflect 2006 estimated hotelling emissions. Based on the adjusted results, we estimate that over two million people live in the area around the ports that has predicted cancer risks of greater than 10 in a million due to hotelling emissions from ocean-going vessels.

Estimates of potential cancer risks from hotelling emissions at these two ports would represent the upper range of cancer risks, given the magnitude of hotelling emissions in the San Pedro Bay area and the proximity of the emissions to highly urbanized areas. Semi-quantitative estimates of the relative impact of hotelling emissions for other areas can be made based on a comparison of the relative magnitude of emissions and the proximity of the emissions to urbanized areas. For example, one would expect that the potential cancer risk estimate for the Port of Oakland would be about 20 percent of the estimate for the Ports of Los Angeles and Long Beach, while the cancer risk estimates for the Port of San Diego would be about 90 percent lower.

ARB staff is currently conducting a diesel PM exposure assessment study for the West Oakland community which includes the Port of Oakland that will be similar in scope as the study completed for the Ports of Los Angeles and Long Beach. Staff expects a draft report on the West Oakland study to be released in late November.

B. Non-Cancer Risk

Staff estimates that current exposure to direct and secondary diesel PM emissions from at-berth ocean-going vessel auxiliary engines can be associated with about 61 premature deaths per year. Due to the location of the ocean-going vessels' operations, their emissions were assumed to affect the population only within the county in which the vessels are docked.

Using the 2006 statewide estimate of directly emitted diesel PM hotelling emissions and the relationship of diesel PM to PM-mortality derived from Pope et al. (2002), we estimate approximately 39 premature deaths (11 to 68, 95 percent confidence interval (95% CI)) per year statewide due to uncontrolled, directly emitted diesel PM from at-berth ocean-going vessel auxiliary engines.

Staff actually developed basin-specific factors for the health impacts assessment of emissions from the operation of auxiliary engines on at-berth ocean-going vessels. These basin-specific factors were developed using basin-specific diesel PM concentrations and emissions for the year 2000. The basin-specific factors were applied to the county where each port is located to estimate health impacts.

Using these basin-specific factors and after adjusting for population changes between 2000 and 2006, staff estimates that 580 tons of emissions from the operation of auxiliary engines on at-berth ocean-going vessels for the year 2006 are associated with approximately 39 annual deaths (11 – 68, 95% CI). Estimates of other health impacts, such as hospitalizations and asthma symptoms, were calculated using basin-specific factors developed from other health studies. Details on the methodology used to calculate these estimates can be found in Appendix A of the Emission Reduction Plan for Ports and Goods Movement in California (ARB, 2006).

In addition to directly emitted PM, diesel exhaust contains NOx, which is a precursor to nitrates, a secondary diesel-related PM formed in the atmosphere. Lloyd and Cackette (2001) estimated that secondary diesel $PM_{2.5}$ exposures from NOx emissions can lead to additional health impacts beyond those associated with directly emitted diesel $PM_{2.5}$ (Lloyd and Cackette, 2001). To quantify such impacts, staff developed population-weighted nitrate concentrations for each air basin, as described in the Technical Support Document, Chapter V.

Using the 2006 statewide estimate of NOx hotelling emissions and the relationship of NOx/nitrate to PM-mortality, we estimated approximately 22 (6 – 36, 95% CI) premature deaths per year statewide due to uncontrolled, secondary diesel PM from at-berth ocean-going vessel diesel auxiliary engines.

In addition to PM-mortality, we estimate that the 2006 estimated emissions (directly emitted and secondary sources) from at-berth ocean-going vessel auxiliary engines will result in the following non-cancer health impacts:

- 13 hospital admissions due to respiratory causes (8 – 18, 95% CI)
- 24 hospital admissions due to cardiovascular causes (15 – 37, 95% CI)
- 1,800 cases of asthma-related and other lower respiratory symptoms (700 – 2,800, 95% CI)
- 150 cases of acute bronchitis (0 – 320, 95% CI)
- 11,000 work loss days (9,000 – 12,000, 95% CI)
- 61,000 minor restricted activity days (50,000 – 72,000, 95% CI)

5. SUMMARY OF THE PROPOSED REGULATION

Staff is proposing that the Board approve adoption of a regulation, pursuant to its authority under HSC sections 38500 et seq., 43013 and 43018, which would apply to the emissions from diesel auxiliary engines on oceangoing vessels docked at California ports. As a companion to that regulation, staff is proposing that the Board also approve adoption of identical provisions as an airborne toxic control measure (ATCM), pursuant to its authority under HSC section 39666, which would complement the regulation and provide maximum notice to the regulated community of the regulatory requirements on ocean-going vessels. The regulation and ATCM are hereinafter collectively referred to in the singular. The following sections provide more details about the proposed regulation.

Applicability

The regulation would apply to any person who owns, operates, charters, rents, or leases any container ship, passenger ship, or refrigerated cargo ship (also known as "reefer") that visits a California port. The regulation would also apply to any person who owns or operates a port or terminal located at a port where container, passenger, or refrigerated cargo (reefer) ships visit. These ports include Los Angeles, Long Beach, Oakland, San Diego, San Francisco, and Hueneme. For purposes of complying with the proposed regulation, the ports of Los Angeles and Long Beach are considered as one port.

The regulation applies to both U.S.-flagged vessels and foreign-flagged vessels. Foreign-flagged vessels are vessels registered under the flag of a country other than the United States.

Exemptions

The proposed regulations contain general and specific exemptions. Under the general exemptions, vessels in "innocent passage;" vessels owned or operated by local, state, federal or foreign governments in government non-commercial

service; steamships; and auxiliary engines using natural gas are exempt from the regulations in their entirety. A steamship is an ocean-going vessel whose primary propulsion and electrical power are provided by steam boilers. In addition, there are particular exemptions from specified portions of the regulations for emergency events and delays caused by federal agency inspections.

Options to Reduce Emissions

Limited Engine Use Option

The proposed regulation allows for two options to reduce hotelling emissions: (1) ship operators can either shut down their auxiliary engines while in port (except for three or five permissible hours of operation per visit), or (2) they can reduce the at-berth emissions from those auxiliary engines by specified percentages while docked.

The "limited engine use" option in the proposed regulation requires that the operators of container ships, passenger ships, and reefers that visit California ports shut down their auxiliary engines for most of their stay while hotelling. Specifically, these auxiliary engines must be shut down for 50 percent of a fleet's total visits to a California port in 2014 and 80 percent of the fleet's total visits to a port in 2020. While auxiliary engines are shut down, the ship's onboard electrical needs must be satisfied by some other source of power. The source of electrical power used instead of the auxiliary engines must be provided either by the grid or by another power source that meets specified emission standards.

Fleets that do not make a minimum number of annual visits to a California port are exempt from the auxiliary engine limitations for that port. The specified threshold for applying the engine shutdown requirement is less than 25 total annual visits by a container vessel fleet or reefer vessel fleet to a port. For passenger vessel fleets, this threshold is less than five visits. However, these minimum thresholds notwithstanding, the regulation requires a vessel to use shore power if it is equipped to do so, and it visits a berth equipped to provide compatible shore power.

As noted, to provide for sufficient time to connect and disconnect electrical lines for shore power, the proposed regulation allows the auxiliary engines to operate for up to three hours during a visit, or five hours during a visit for vessels that lose power during the process of switching power from the vessel's auxiliary engines to shore power. This time period may be extended due to circumstances beyond the control of the vessel operators, such as emergency events or delays resulting from obligations imposed by federal agencies (for example, the U.S. Coast Guard or some other branch of the Department of Homeland Security).

Emission Reduction Option

An alternative to the "limited engine use" approach is the "emissions reduction option." Operators choosing this option are required to reduce their auxiliary engine emissions at a port by specific percentages and by specific dates. The compliance dates vary based on the types of emission reduction techniques applied to the fleets.

The emission reduction techniques that could be applied to a fleet include: 1) using selected vessels for grid-supplied power based on potential auxiliary engine emission reductions rather than fleet visit percentages; 2) using distributed generation equipment to provide power to a vessel; 3) using alternative emission controls onboard a vessel or located adjacent to the vessel; and 4) using a combination of these techniques.

For option 1, the emission reduction targets are aligned with the limited engine use approach: the NOx and PM emissions from the fleet's auxiliary engines at a port must be reduced by 50 percent from the baseline fleet emissions by 2014 and by 80 percent by 2020. For options 2 and 3, in which alternative control technologies are implemented, the NOx and PM emissions from the fleet's auxiliary engines at a port must be reduced by 20 percent from the baseline fleet emissions by 2010, 40 percent by 2012, 60 percent by 2014, and 80 percent by 2016. For option 4, in which a combination of approaches is implemented, NOx and PM emissions must be reduced by 20 percent from the baseline fleet emissions by 2012, 50 percent by 2014, and 80 percent by 2020.

Staff is proposing earlier compliance dates (2010 and 2012) for vessel operators choosing alternative emission controls to reduce their fleet's hotelling emissions rather than using grid supplied shore power, because of the significant lead time required to design and install a grid-based shore power application, which can be up to several years. If alternative controls or alternative shore power are available much earlier than 2014 and a vessel operator chooses the emission reductions option, then staff expects to begin achieving emission reductions from these options soon after the regulation is effective in late 2008.

The proposal provides default values for making the emission reduction calculation, including default values for emission factors and power requirements, in lieu of more specific values. In addition, the proposal provides procedures for determining control factors and applicable emission testing procedures.

Sources of electrical power, other than the grid, that are used to comply with the emission reduction option would be required to satisfy additional requirements. Before January 1, 2014, distributed generation equipment must satisfy the emission standards applicable to a newly manufactured spark-ignited off-road engine. As of January 1, 2014, all distributed generation would be subject to a

more stringent emission standard that is equivalent to a spark-ignited engine using Best Available Control Technology (BACT). Finally, the source of electrical power must emit no more CO_2 (a greenhouse gas) emissions than a combined-cycle gas turbine—the emissions level that the California Public Utilities Commission recommended for unspecified sources of power.

Recordkeeping and Reporting Requirements

The proposed regulation has reporting and recordkeeping requirements affecting the vessel owners and operators, terminals, and ports.

The reporting and recordkeeping requirements for vessel owners or operators depend upon the compliance option selected by the vessel owner or operator and terminal. The proposed regulation requires a vessel fleet plan to be submitted to the Executive Officer of the ARB in the years prior to the fleet's regulatory compliance dates.

In addition to the vessel fleet plans, the proposal requires an annual statement of compliance to be submitted to the Executive Officer of the ARB certifying compliance with the regulatory requirements for the previous calendar year. As with the vessel fleet plans, the dates for the initial submittals depend upon the compliance option selected by the vessel owner or operator.

The recordkeeping and reporting requirements are simpler for the limited engine use option because the vessel owner or operator choosing that option must track only those vessels that will comply with the 2014 and 2020 shore power requirements. The recordkeeping and reporting requirements for the emission reduction option are more significant because the vessel owner or operator choosing that option must track the emissions of each vessel in the fleet.

A terminal that receives more than 50 vessel visits in 2008 is required to submit a plan to the Executive Officer of the Air Resources Board by July 1, 2009. This plan is required to identify how the terminal will be upgraded to allow vessels to satisfy either the limited engine use option or the emissions reduction option. The terminal is also required to submit plan updates at a frequency that depends on the control strategy selected by the vessel fleet owner or operator and the terminal.

The port is required to submit wharfinger data annually to ARB's Executive Officer. The port's written submittal must document when each vessel visits the port, the berth that the vessel visited, and the dates and times that the vessel was initially tied to the berth and subsequently released from the berth. In addition, the terminal operator is required to keep records of electricity usage for shore power and equipment breakdowns that affect a vessel's ability to comply with the limited engine use option or the emission reduction option.

Violations and Severability

The proposal includes a violations provision that provides, among other things, that any violation of any part of the regulation would constitute a single, separate violation for each hour that the violation occurs. The exception to this would be for violations of the recordkeeping and reporting requirements; a violation of those provisions would constitute a single, separate violation for each day that the violation occurs.

The proposed regulation states that if any part of the regulation is held to be invalid, the remainder of the regulation shall continue to be effective.

6. EMISSION REDUCTIONS

As mentioned earlier, staff assumes that the challenge to the auxiliary engine fuel regulation will ultimately be upheld and that the fuel regulation will provide significant emission reductions from auxiliary engines on ocean-going vessels. The proposed at-berth ocean-going vessel regulation is expected to provide additional significant emission reduction benefits. Staff projects that the proposed regulation would reduce hotelling diesel PM and NOx emissions from container ships, passenger ships, and refrigerated cargo ships by 50 percent and 75 percent relative to levels expected to be emitted in 2014 and 2020, respectively. These emission reductions will occur in areas at and near ports where environmental justice concerns are especially prevalent.

In addition, hotelling CO_2 emissions are expected to be reduced by 122,000 to 242,000 metric tons in 2020. These estimated CO_2 reductions take into account the CO_2 emissions associated with the generation of electricity for shore power. The CO_2 benefits from this regulation—which will assist the State with meeting the AB 32 targets for greenhouse gas reductions—are discussed in more detail later in this staff report.

Figures 1 and 2 show the projected diesel PM and NOx hotelling emissions for container ships, passenger ships, and reefer ships, with and without implementation of the proposed regulation.

Figure 1: Projected Diesel PM Emissions with and without the Proposed Regulation

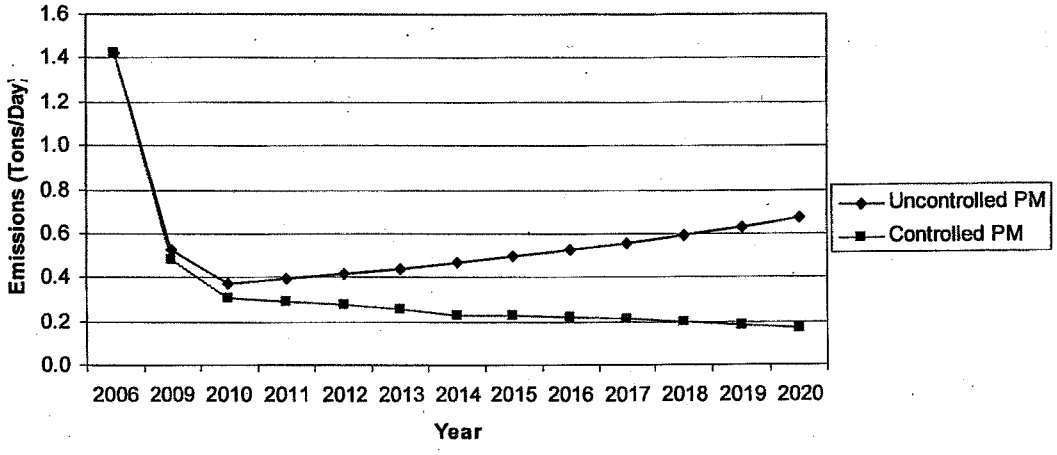
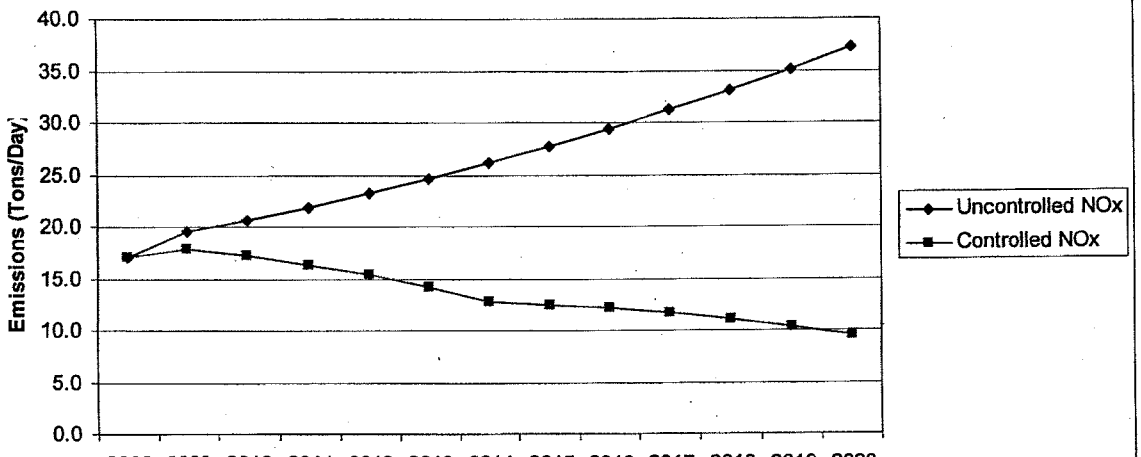


Figure 2: Projected NOx Emissions with and without the Proposed Regulation



As summarized in Table 4 below, staff estimates that approximately 1,100 tons of diesel PM and 61,700 tons of NO_x will be removed from California's air between 2006 and 2020 due to the implementation of the proposed regulation.

Table 4: Emission Benefits from Implementation of the Proposed Regulation

	PM	NO_x
Total Emission Reductions 2006 to 2020 (Tons)	1,100*	61,700*
Annual Average Reductions (Tons per Year)	85	4,700

*For the container-ship category, the regulatory period is 2009 – 2030 to account for ship turnover. Total emissions reductions to 2030 are 2,600 tons of diesel PM and 140,000 tons of NOx.

7. RISK REDUCTION

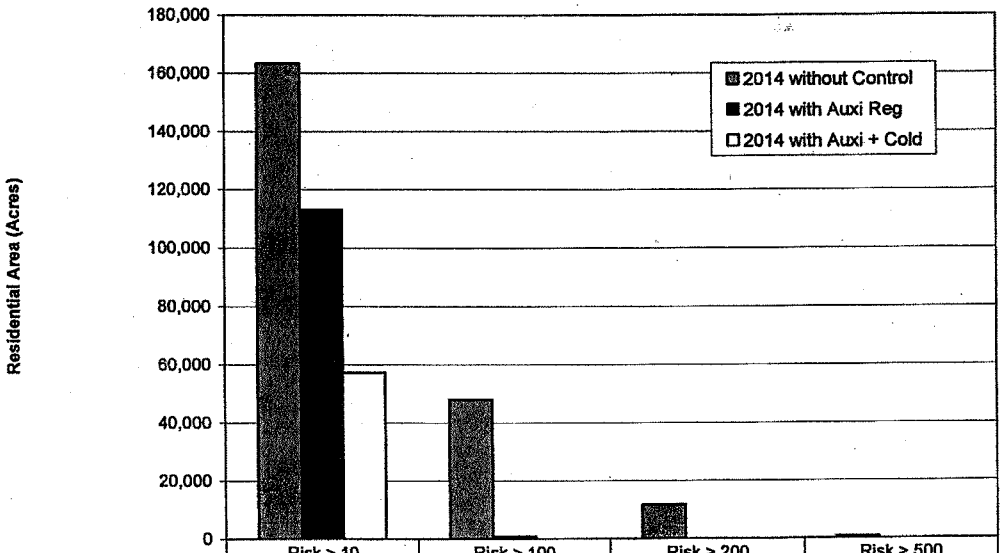
A. Cancer Risk

The emission reductions obtained from the proposed regulation would result in lower ambient PM levels and reductions in exposure to diesel PM. These reductions would result in a corresponding reduction in potential cancer risk. Because ARB's auxiliary engine fuel regulation would significantly reduce diesel PM hotelling emissions from auxiliary engines[1], the potential cancer risks from exposures to the projected 2014 and 2020 emissions levels after implementation of the proposed regulation were estimated and compared to those of 2014 and 2020 emission levels from implementation of the auxiliary engine fuel regulation to determine how the potential risks will change.

As shown in Figures 3 through 6, we expect a significant decline in the number of people exposed to elevated risk levels from hotelling emissions and the acres impacted as the auxiliary engine fuel regulation is implemented. In addition to this reduction, the proposed At-Berth Ocean-Going Vessel regulation will reduce the number of residential acres and population exposed to diesel PM concentrations greater than 10 per million by an additional 50 percent by 2014 and 70 percent by 2020. More importantly, all higher risk levels of greater than 100 in a million are eliminated due to implementation of the proposed regulation.

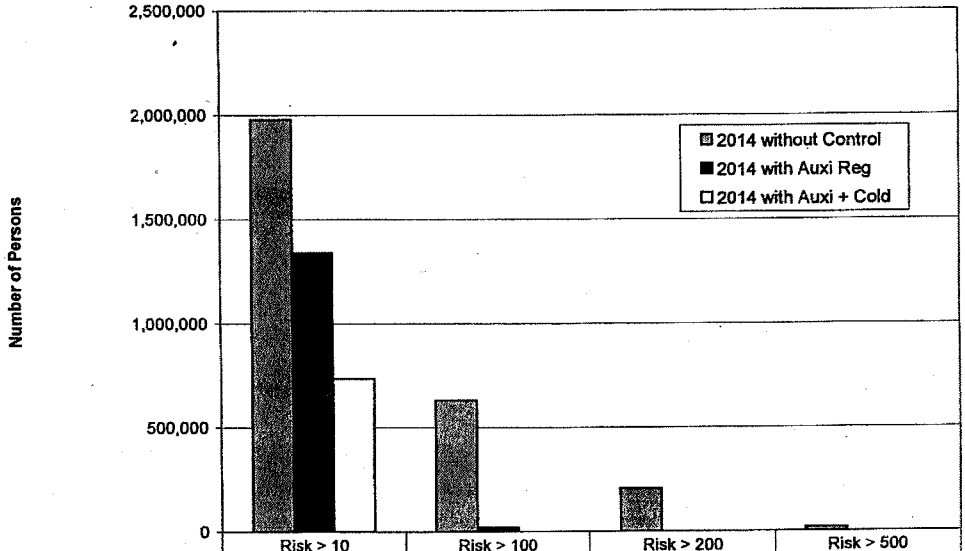
[1] See title 13 CCR § 2299.1 and title 17 CCR § 93118. At the time this ISOR was published, those regulations had been challenged in federal district court and undergoing appeal at the Ninth Circuit Court of Appeals. Pacific Merchant Shipping Ass'n v. Cackette, (E.D.Cal. Oct 05, 2007) 2007 WL 2914961 (No. Civ. S-06-2791-WBS-KJM). The analysis presented in this portion of the ISOR assumes those auxiliary engine regulations will ultimately be upheld on appeal.

Figure 3: Projected Residential Areas Impacted by Hotelling Emissions at POLA/POLB by 2014



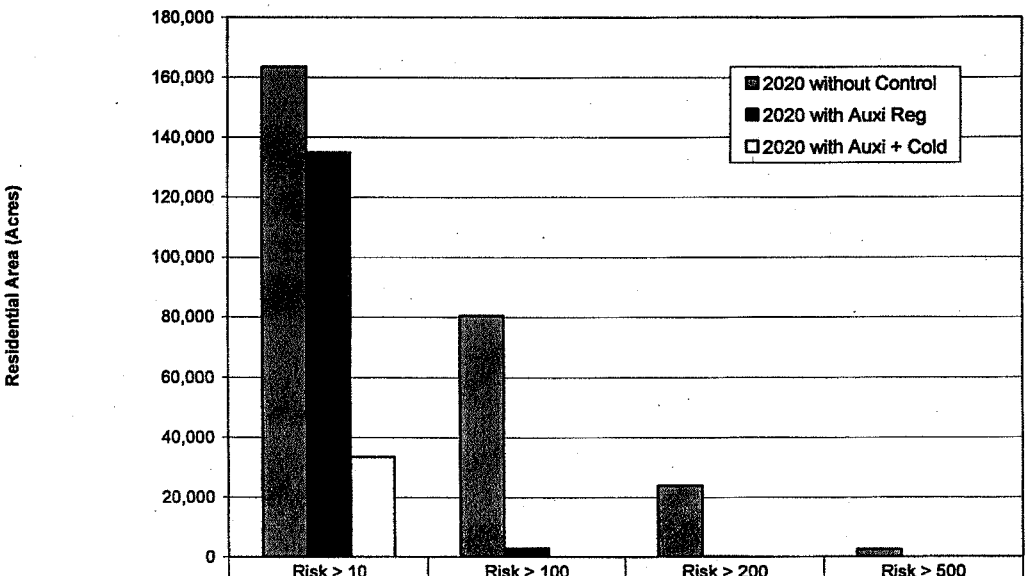
	Risk > 10	Risk > 100	Risk > 200	Risk > 500
2014 without Control	163,435	48,146	11,653	761
2014 with Auxi Reg	113,016	939	0	0
2014 with Auxi + Cold	57,269	0	0	0

Figure 4: Projected Numbers of Population Affected by Hotelling Emissions at POLA/POLB by 2014



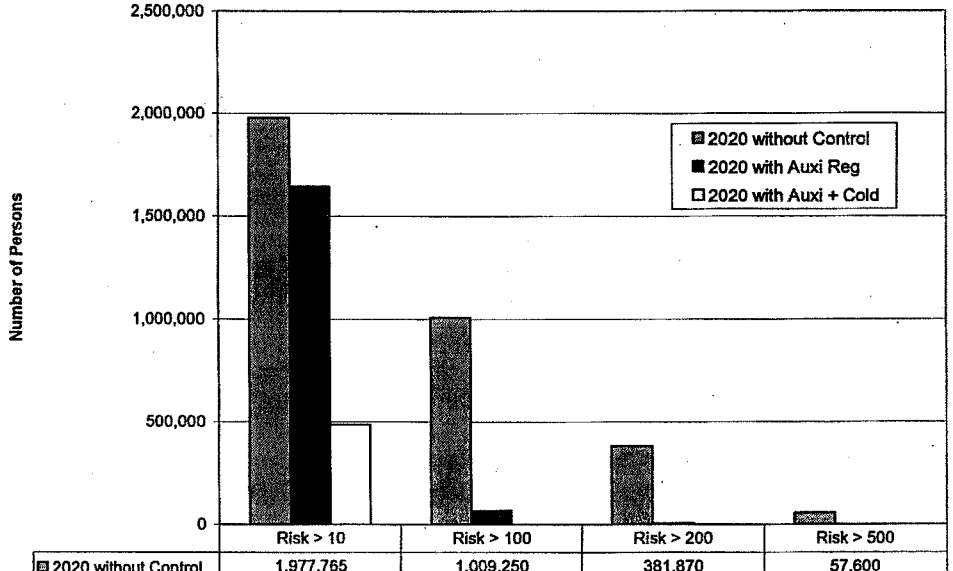
	Risk > 10	Risk > 100	Risk > 200	Risk > 500
2014 without Control	1,977,764	631,799	206,577	17,917
2014 with Auxi Reg	1,339,600	20,800	0	0
2014 with Auxi + Cold	736,000	0	0	0

Figure 5: Projected Residential Areas Impacted by Hotelling Emissions at POLA/POLB by 2020



	Risk > 10	Risk > 100	Risk > 200	Risk > 500
2020 without Control	163,435	80,457	23,979	2,540
2020 with Auxi Reg	134,820	2,955	119	0
2020 with Auxi + Cold	33,517	0	0	0

Figure 6: Projected Numbers of Population Affected by Hotelling Emissions at POLA/POLB by 2020



	Risk > 10	Risk > 100	Risk > 200	Risk > 500
2020 without Control	1,977,765	1,009,250	381,870	57,600
2020 with Auxi Reg	1,644,856	65,856	6,180	0
2020 with Auxi + Cold	485,000	0	0	0

B. Non-Cancer Risk

The emission reductions obtained from this regulation will result in lower ambient PM levels and reduced exposure to diesel PM. Staff estimates that approximately 280 premature deaths (78 – 480, 95 percent confidence interval (95% CI)) statewide will be avoided by the year 2020 from the implementation of the proposed regulation. Estimates of other health effects avoided statewide include:

- 60 hospital admissions due to respiratory causes (38 – 83, 95% CI)
- 110 hospital admissions due to cardiovascular causes (70 – 170, 95% CI)
- 8,200 cases of asthma-related and other lower respiratory symptoms (3,200 – 13,000, 95% CI)
- 680 cases of acute bronchitis (0 – 1,400, 95% CI)
- 49,000 work loss days (42,000 – 57,000, 95% CI)
- 280,000 minor restricted activity days (230,000 – 330,000, 95% CI)

8. ENVIRONMENTAL IMPACT

No significant adverse environmental impacts are expected to occur from adoption of, and compliance with, the proposed requirements for ocean-going vessels at berth. Implementation of the proposal would reduce directly emitted and secondarily formed PM levels, provide both near source and regional risk reduction, and contribute to the overall effort of reducing PM mortality, hospital admissions, and lost work days.

9. IMPACT ON GLOBAL WARMING

As noted, the Board will consider, at its October 2007 meeting, reclassifying shore power (now referred to as Green Ports) from an early action measure to a discrete early action measure pursuant to AB 32. The proposed regulation for ocean-going vessels at-berth would result in significant CO_2 reductions and its adoption would fulfill the Board's commitment to pursue shore power as an early action measure, assuming the Board accepts the staff's recommendation in October to include the measure as an early action item.

The proposal's primary emission reduction strategy is to allow a ship to utilize grid-based shore power instead of onboard electrical generation from diesel-fueled auxiliary engines. The CO_2 emissions from California's utility grid are much cleaner than diesel-fueled auxiliary engines on ships. In addition, new state mandates (SB 1368[2] and AB 32) will result in CO_2 emissions from the grid declining between now and 2020. Consequently, CO_2 emissions from

[2] SB 1368 (Stats. 2006, ch. 598).

ocean-going vessels at-berth are expected to be reduced by 122,000 to 242,000 metric tons in 2020.

The proposed regulation will allow the use of alternative technologies to achieve required emission reductions. These alternatives may include ship-side technologies, such as post-combustion devices, alternative fuels, or cleaner engines, or shore-side technologies, including distributed generation or emission-capture-and-treatment devices (so-called "bonnet" systems). These technologies—although attractive for early deployment for NOx and diesel PM reductions—will most likely be less effective in reducing GHG emissions when compared to grid-based shore power, but they are permitted as specified in the proposal.

For sources of electricity other than the grid for providing shore power to the ships, the proposed regulation limits the CO_2 emissions to 500 grams per kilowatt-hour (1,100 lbs CO_2/MW-hr). This emission standard will prohibit the use of electrical generation technologies that emit much higher levels of CO_2, such as diesel engines and less efficient spark-ignited engines.

The post-combustion technologies—selective catalytic reduction (SCR), diesel particulate filters (DPFs), and diesel oxidation catalysts (DOCs)—tend to increase CO_2 emissions due to increased fuel use. However, the DPFs and DOCs remove black carbon, a component of diesel PM and a likely contributor to global warming.

For the emission-capture-and-treatment devices (e.g., Advanced Cleanup Technologies' "bonnet" system), there would be a much larger CO_2 penalty because there is an auxiliary burner on the treatment unit for reheating the stack gases so that the SCR operates effectively. In addition, a vessel would use a bonnet system to allow the continued operation of the onboard auxiliary engines. Thus, the auxiliary engines aboard the ships would still be operating, along with the treatment unit's burner. On the other hand, this alternative technology would capture and treat the NOx and PM emissions from the boilers on the ships—something that shore power would not do—so the increase in CO_2 emissions would need to be balanced against the additional NOx and PM emission reductions.

Most of these technologies are at the proof-of-concept stage, and ARB staff cannot at this time predict with certainty the extent of their deployment in the future. Therefore, we are unable to project the impact of such alternatives on overall CO_2 emission reductions under this program.

10. ECONOMIC IMPACTS

Staff assumes that the most widely deployed technique for meeting the requirements of the proposed regulation will be grid-based shore power. This approach satisfies the "limited engine use" option and will probably be the

technique of choice for the emissions reduction option. Consequently, staff's economic analysis addressed the use of grid-based shore power only.

Staff estimates the total statewide costs for affected businesses and port authorities to comply with the proposed regulation to be approximately $1.8 billion, in 2006 dollars. This includes costs directly resulting from compliance with the proposed regulation (e.g., shutting down engines, recordkeeping, reporting), as well as those costs that are not directly required by the regulation, but are expected, as terminals and ports prepare to accommodate vessels that shut down their engines at berth (e.g., installation of shore power capabilities). Annually, the costs are expected to vary from $30 million to $137 million. The low end of the range represents a year when the only major capital expenditures are for retrofitting container ships due to repositioning, and the high end of the range represents a year when capital expenditures are being made for shoreside infrastructure and for retrofitting a considerable number of ships to meet the 2020 milestone. The total statewide annual costs to private business include recovery of capital expenditures, both aboard the ships and at the ports, and operating costs, which are labor costs and net energy costs.

Since 25 of the 35 vessel fleets affected by the proposed regulation are container-ship fleets, for the purposes of this proposed regulation, the typical ship company refers to a company operating container ships. The total costs to a typical ship company complying with the proposed regulation, including capital and ongoing costs are estimated to be about $34 million. This cost would be distributed over the years 2009 to 2020 for passenger ship companies and reefer ship companies and to 2030 for container ship companies. About 40 percent of the cost is associated with modifying additional ships to replace ships that have been re-deployed away from California ports. Annual costs would vary between $600,000 and $3 million per year, with the average cost of $1.5 million per year over this time period. The low end of the range represents a year when no major capital expenditures are made, and the high end of the range represents a year where capital expenditures are made for both new ships as well as replacement ships that are rerouted.

For the other passenger ship and reefer categories, the total costs for a typical ship company to comply with the proposed regulation, including capital and ongoing costs, are estimated to be about $3.2 million. This cost would be distributed over a 12-year period, from 2009 to 2020. Annual costs would vary between $150,000 and $500,000 per year, with the average cost of $260,000 per year over this time period.

Similarly, the total costs to a typical terminal operator complying with the proposed regulation, including capital and ongoing costs, are estimated to be about $11 million. About 20 percent of the cost is attributed to labor costs and the other 80 percent for capital costs. This cost would be distributed over a

12-year period, from 2009 to 2020. Annual costs would vary between $500,000 and $1.1 million per year, with the average cost of $1 million per year over this time period. The low end of the range represents a year where no major capital expenditures are made, and the high end of the range represents a year where capital expenditures are made for shore-side improvements. With 31 terminals and 35 vessel fleets affected by the proposed regulation, the cost to a typical business would be $26 million.

Vessel owners or operators, terminals, and ports would have additional recurring costs associated with recordkeeping and reporting. Reporting requirements begin July 1, 2009, and recordkeeping requirements begin January 1, 2010. For the vessel owner or operator, the costs associated with reporting and recordkeeping will vary between $600 and $12,000 annually. The higher end of this range applies when the ship company chooses to comply with the emission reduction option of the proposed regulation, and the lower end of the range represents the costs for ship companies that comply with the limited engine use requirement. For the terminal operators and ports, the costs associated with reporting and recordkeeping are about $800 annually.

Staff does not anticipate any small businesses being affected by the proposed regulation due to the large capital and operating costs associated with ocean-going vessel operations.

The proposed regulation achieves these reductions automatically as a co-benefit of the diesel PM and NOx emission reductions. Because the proposed regulation is primarily a diesel PM and NOx control measure, and it will not mandate any additional requirements in order to reduce CO_2 emissions, there will be effectively zero costs involved in achieving these CO_2 emission reductions. Therefore, the cost-effectiveness for reducing CO_2 as a co-benefit of achieving the primary reductions in diesel PM and NOx emissions is essentially zero dollars per pound of CO_2 reduced.

11. COST TO LOCAL AGENCIES

The governmental agencies affected by the proposed regulation are the port authorities, which are branches of the local city governments. The ports affected by the proposed regulation are the Ports of Hueneme, Long Beach, Los Angeles, Oakland, San Diego, and San Francisco. Additionally, the cruise terminal at the Port of Long Beach is owned by the City of Long Beach

The costs to be expended by the port authorities to add shore-power equipment to their facilities ranges from $4 million to $86 million. Staff does not expect ports to have a fiscal impact—defined as the costs incurred to the local agencies in the three fiscal years starting with the 2007/2008 fiscal year—until the second year. At this time, staff anticipates that the port authorities would begin to make

payments during fiscal years 2008/2009 and 2009/2010 for the necessary shore-power equipment to satisfy the 2014 milestone. The estimated fiscal costs for the ports range from $600,000 to $7.4 million for the fiscal years 2007/2008 and 2009/2010.

Staff assumes that the landlord ports will work with their tenants, the terminal lessees, to provide the shoreside infrastructure necessary to meet the requirements of the proposed regulation. Furthermore, staff assumes that the landlord ports will eventually recover their capital costs through modifications to terminal leases, while the non-landlord ports will recover their capital costs through fees collected from the carriers.

12. COST-EFFECTIVENESS

Cost-effectiveness is expressed in terms of regulatory compliance costs (dollars) per unit of air pollutant reduced (ton). Except for container ships, the cost-effectiveness for the proposed regulation was determined by dividing the total cost of the proposed regulation by the total tons of air pollutants reduced from 2009 to 2020. For container ships, the emission reductions out to 2030 were included in the calculation to account for that category's ship turnover rate.

Staff estimates the overall cost-effectiveness of the proposed regulation, in terms of dollars per ton of NOx emission reduction, to be about $12,800 per ton, if the total cost is attributed solely to the NOx emission reductions. Staff estimates the overall cost-effectiveness of the proposed regulation, in terms of dollars per ton of PM emission reduction, to be is about $690,000 per ton if the total annualized cost is attributed solely to the PM reduction. Because the proposed regulation reduces significant amounts of both NOx and PM, staff also evaluated cost-effectiveness by attributing half the total annualized cost to the PM emission reductions and half to the NOx emission reductions. The resulting cost-effectiveness values using that method are $6,400 per ton of NOx reduced and $345,000 per ton of PM reduced.

For perspective, the cost-effectiveness values of the proposed regulation are compared to that for other regulations recently adopted by the Board. For example, the *Heavy Duty Urban Bus Engines and Fleet Rule for Transit Agencies*, approved by the Board in September 2005, estimated a cost-effectiveness of nearly $68,000 per ton of NOx reduced, assuming all of the costs are attributed to NOx emissions reductions. The average cost-effectiveness of the proposed regulation is below the urban bus regulation's value, as are the calculations for the individual terminals, with the exception of one terminal at Oakland, which is slightly above this cost-effectiveness level.

The highest cost-effective values for regulations adopted by the Board to reduce PM emissions was about $320,000 per ton of PM reduced for the *Diesel*

Particulate Control Measure for On-Road Heavy-Duty Diesel-Fueled Vehicles Owned or Operated by Public Agencies and Utilities. If the total costs of the proposed regulation are split between NOx emissions reductions and diesel PM reductions, then about half of the terminals are below this cost-effectiveness threshold. Again, the auxiliary engine fuel regulation already has reduced hotelling diesel PM emissions by 70 percent.

The cost-effectiveness was calculated for each affected ship terminal in California. Table 5 shows the cost-effectiveness estimate for the proposed regulation expressed in three ways for each type of affected ship category. All costs are in equivalent 2006 expenditure dollars.

Table 5: Summary of Cost-Effectiveness for Shore-Power

	All Costs for NOx Only	All Costs for PM Only	Half Costs for NOx	Half Costs for PM
	(Dollars per Ton of Pollutant Reduced)			
Container Ships— POLA/POLB	$11,000 to $32,000	$400,000 to $1.1 million	$5,500 to $16,000	$200,000 to $550,000
Container Ships-- Oakland	$11,500 to $71,000	$400,000 to $2.5 million	$5,800 to $36,000	$200,000 to $1.2 million
Passenger Ships	$13,000 to $47,000	$440,000 to $1.6 million	$6,400 to $23,000	$220,000 to $810,000
Reefer Ships	$16,000 to $30,000	$600,000 to $1 million	$7,900 to $15,000	$300,000 to $510,000

13. FEASIBILITY OF PROPOSED REGULATION

The proposed regulation allows for two options to reduce hotelling emissions: 1) ship operators can either shut down their auxiliary engines while in port (except for three or five permissible hours of operation per visit), or 2) they can reduce the at-berth emissions from those auxiliary engines by specified percentages while docked.

Staff expects most ship operators to comply with the limited engine use option and to use shore power provided by the grid. However, some ship operators may decide to reduce their fleet hotelling emissions by applying a number of other techniques to their fleet, including using alternative sources of power at the berth (e.g. distributed generation equipment), and using onboard or shore-based engine emission control technologies.

A. Grid Supplied Shore Power

Grid-supplied shore power has been proven and is technologically feasible. Shore power is already being used or will soon be used for passenger ships, container ships, bulk ships and oil tankers at California ports. POLA and POLB have committed to adding shore power to their passenger ship terminals and to several of their container ship terminals. Ships will soon be utilizing shore power at two additional container terminals at POLA and at a tanker terminal at POLB. Several passenger ships that visit California ports have been retrofitted to connect to shore power, and some container-ship owners have committed to adding shore power equipment to their new-builds and retrofitting some of their existing fleet with shore-power capabilities.

Although this is a proven technology, there are challenges to implementing shore power as an emission reduction measure. Modifications would be needed to both terminals and ships to utilize grid-based shore power as a method for reducing hotelling emissions. The modifications that would be necessary to install and utilize shore power are discussed in more detail in Chapter VII of the Technical Support Document.

B. Alternative Emission Reduction Measures

An alternative to the limited engine use compliance approach is the "emissions reduction option," in which the fleets reduce their auxiliary engine emissions at a port by specified percentages and dates. The emission reduction techniques that could be applied to a fleet include: 1) using select vessels for grid-supplied power based on potential auxiliary engine emission reductions rather than fleet visit percentages; 2) using alternative sources of power (distributed generation equipment) to provide power to a vessel; 3) using alternative emission controls onboard a vessel or located adjacent to the vessel; and 4) using a combination of these techniques.

Alternative emission control technologies for auxiliary engines could include alternative fuels and post-combustion control measures. Emission control equipment for auxiliary engines could be placed at the berth or onboard the ships. While many control technologies have been proven to reduce emissions of PM and NOx from land-based diesel-fueled engines, there is limited experience in applying these technologies to marine vessel engines. In addition, there are currently no emission control strategies verified by the ARB for marine applications. Some of these technologies have been applied to harbor craft engines, but those applications were on much smaller engines than the auxiliary engines on ocean-going vessels.

A few demonstration projects have been conducted on auxiliary ocean-going vessel engines. These involved the use of portable distributed generation, a

seawater scrubber, biodiesel fuel, an on-demand water/fuel emulsion system, and selective catalytic reduction. However, because these technology demonstrations are still at an early stage, ARB staff cannot predict at this time the future deployment or feasibility of these alternative technologies as effective emission control measures for auxiliary engines on ships at berth.

14. ALTERNATIVES CONSIDERED

Staff considered two regulatory alternatives: 1) targeting the highest-emitting ships to obtain the necessary reductions, or 2) using best available control technology (BACT) on auxiliary engines while the ship is hotelling.

Alternative 1 would target the ships that make the most visits to specific ports and make them use shore power or an equivalent control technology to reduce hotelling emissions. For example, a requirement under this regulatory alternative might state "container ships making more than four visits to a California port in 2014 must turn off their engines or use an alternative control technology."

Staff estimated that this regulatory alternative would be as effective as the proposed regulation; however, staff did not pursue this alternative because of the complexity and difficulty of tracking the ships that were required to reduce emissions. Many of these ships would be repositioned elsewhere, while other ships would replace them in California service, creating excessive recordkeeping requirements and practical enforcement challenges.

Alternative 2 requires vessel operators to install BACT on their auxiliary engines. Currently, few emission-control technologies that have been used successfully on land-based engine applications have been demonstrated on marine engines. Nevertheless, for the purpose of determining a potential cost-effectiveness of this alternative, staff selected selective catalytic reduction (SCR) for NOx emissions reductions and diesel oxidation catalyst (DOC) for diesel PM emissions reductions.

Installing this equipment on the same ships affected by the proposed regulation would cost less than the overall cost of the proposed regulation. However, the reduction of PM emissions would be considerably less with this BACT alternative because DOCs achieve only about 25 percent PM emission reductions. Furthermore, the varying load of the auxiliary engines during transiting, maneuvering, and hotelling would compromise the performance of the SCR, achieving less than 80 percent emissions reduction.

Considering the unproven application of these technologies for marine engines, fewer total emissions reductions, and much higher cost-effective values for diesel PM emissions reductions, staff did not pursue this alternative regulatory alternative.

15. OUTREACH

ARB's outreach efforts for the proposed regulation began during the development of its draft cold-ironing feasibility report (Evaluation Report). ARB staff first discussed a plan for analyzing the cost-effectiveness of cold-ironing ocean-going vessels at a public consultation meeting on November 9, 2004.

During the Evaluation Report's development, staff visited four ports in California: Los Angeles, Long Beach, Oakland, and San Diego. Staff also visited three cold-ironing applications in the State. Staff also held conference calls or met with shipping companies, utility companies, environmental groups, and other organizations interested in cold-ironing applications.

ARB staff solicited public input on the Evaluation Report when it was released in March 2006 and considered the comments received when they began developing draft concepts for a shore power regulation.

Staff also coordinated with the Ports of Los Angeles and Long Beach in the development of the San Pedro Bay Ports Clean Air Action Plan (CAAP), which was released in November 2006. The CAAP identifies shore power as a measure to control hotelling emissions and identifies specific terminals and berths that will be equipped with shore power capability and the expected completion dates for these projects. ARB staff considered the CAAP's shore power requirements as we began our development of the proposed regulation with a goal of developing a proposed measure that would be consistent with the CAAP and complementary to the ports' ongoing emissions reduction efforts.

ARB staff and interested parties formed a workgroup in early 2007 to assist staff with developing a shore power regulation. Many of the stakeholders that assisted ARB staff with developing the Evaluation Report were also members of the workgroup.

Five shore power workgroup meetings were held between January and August 2007. At the end of that process, ARB staff decided that it was appropriate to transition from the workgroup process to a more formal rulemaking process. Subsequently, staff held four public workshops in September 2007 to discuss the draft proposed regulation. Two of these workshops were evening meetings held in community centers near ports, where staff could seek input from those communities most impacted by hotelling emissions.

ARB staff created a shore power electronic list serve and webpage to notify interested parties of the workgroups and to post drafts of the regulation before they were discussed at the meetings. Over 2000 individuals and companies have subscribed to the shore power list serve.

In addition to the workgroup and workshop meetings, staff's outreach efforts also included hundreds of personal contacts via telephone and electronic mail; numerous individual meetings with interested parties, including port representatives, environmental groups, utility representatives, and shipping representatives; and informational visits to ports. Staff visited the Port of Hueneme in early 2007, where staff had the opportunity to observe refrigerated cargo ships carrying break-bulk products and discuss regulation development with port staff. ARB staff also toured a containerized refrigerated cargo ship at the Port of San Diego. At the Port of Oakland, ARB staff toured a container ship that was equipped with shore power capability and observed a demonstration of a portable distributed generation power source for powering container ships while in port.

16. ENVIRONMENTAL JUSTICE

A public process that involves all parties affected by the proposed regulation is an important component of ARB rulemaking activities. The proposal is consistent with the ARB's environmental justice policy to reduce health risks from toxic air contaminants in all communities, including low-income and minority communities. The proposed regulation would reduce diesel PM and other emissions from ocean-going vessels at berth in communities surrounding the six major ports of California. The majority of these reductions will occur at the Los Angeles-Long Beach and Bay Area ports, which are surrounded by densely populated areas, including some in low-income and minority communities. Therefore, the proposal will help address environmental justice concerns by reducing emissions and health risks in the areas where hotelling emissions have the greatest impacts.

17. IMPLEMENTATION AND ENFORCEMENT

We believe that ARB staff needs to take the following actions to efficiently and effectively implement the proposed regulation:

- develop an outreach program to inform the 35 ship companies, 31 terminals and six ports affected by the proposed regulation of the regulation's requirements, as well as provide information about incentive programs such as the existing Carl Moyer program and the upcoming Proposition 1B air quality mitigation funds;
- develop recordkeeping and reporting guidance; and,
- provide implementation guidance and assistance as needed.

18. RECOMMENDATION

We recommend the Board approve the proposed regulation for ocean-going vessels at berth presented in Appendix A of the Staff Report. The proposal would provide substantial benefits by requiring diesel-fueled auxiliary engines on

ocean-going vessels to be shut down while in port, or reducing an equivalent amount of emissions by using alternative control methods. These benefits include reducing diesel PM, NOx, and other air pollutant emissions from these engines which, in turn, would reduce human exposure to such pollutants and the concomitant health risk across California, particularly in communities adjacent to the ports. ARB staff believes the proposed regulation and its recordkeeping and reporting requirements are technologically feasible, cost-effective, and necessary to carry out the Board's responsibilities under State law and implement provisions of the Emission Reduction Plan for Ports and Goods Movement approved by the Board in April 2006.

REFERENCES:

California Air Resources Board. *Evaluation of Cold-Ironing Ocean-Going Vessels at California Ports*; March 2006. http://www.arb.ca.gov/ports/shorepower/report.pdf

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California Air Resources Board. *Proposed Amendments to the Exhaust Emission Standards for 2007-2009 Model-Year Heavy Duty Urban Bus Engines and the Fleet Rule for Transit Agencies*; September 2005. (ARB, 2005c)

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Port of Los Angeles and Port of Long Beach. *San Pedro Bay Ports Clean Air Action Plan*; November 2006. http://www.portoflosangeles.org/DOC/CAAP_Tech_Report_Final.pdf and/or http://www.polb.com/civica/filebank/blobdload.asp?BlobID=3451

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Appendix

Proposed Regulations for At-Berth Ocean-Going Vessels

PROPOSED REGULATION ORDER

OPERATIONAL HOUR LIMITS AND OTHER REQUIREMENTS FOR AUXILIARY DIESEL ENGINES OPERATED ON OCEAN-GOING VESSELS AT-BERTH IN A CALIFORNIA PORT

Adopt new section 2299.3, title 13, chapter 5.1, California Code of Regulations (CCR), to read as follows:

(Note: The entire text of section 2299.3 is new language.):

Section 2299.3. Operational Hour Limits and Other Requirements for Auxiliary Diesel Engines Operated on Ocean-Going Vessels At-Berth in a California Port.

(a) *Purpose.*

The purpose of this section is to reduce oxides of nitrogen (NOx) and diesel particulate matter (PM) emissions from the operation of auxiliary engines on container ships, passenger ships, and refrigerated cargo ships while these vessels are docked at berth at a California port. This section reduces emissions by limiting the time during which auxiliary diesel engines are operated on the regulated vessels while such vessels are docked at-berth in a California port, as well as by applying other requirements. This section implements provisions of the Goods Movement Emission Reduction Plan, adopted by the Air Resources Board (ARB) in April 2006, to reduce emissions and health risk from ports and the movement of goods in California. This section also helps achieve the goals specified in the California Global Warming Solutions Act of 2006, established under California law by Assembly Bill 32 (Stats. 2006, ch. 488) and set forth in Health and Safety Code § 38500 et seq.

(b) *Applicability and General Exemptions.*

(1) Except as provided in this subsection (b), this section applies to any person who owns, operates, charters, rents, or leases any U.S. or foreign-flagged container ship, passenger ship, or refrigerated cargo ship that visits a California port. In addition, this section also applies to any person who owns or operates a port or terminal located at a port where container, passenger, or refrigerated cargo vessels visit.

(2) Nothing in this section shall be construed to amend, repeal, modify, or change in any way any applicable U.S. Coast Guard requirements. Any person subject to this section shall be responsible for ensuring compliance with both U.S. Coast Guard regulations and the

requirements of this section, including but not limited to, obtaining any necessary approvals, exemptions, or orders from the U.S. Coast Guard.

(3) The requirements of this section do not apply to:

(A) Ocean-going vessel voyages that are comprised of continuous and expeditious navigation through any of the Regulated California Waters for the purpose of traversing such bodies of water without entering California internal or estuarine waters or calling at a port, roadstead, or terminal facility. "Continuous and expeditious navigation" includes stopping and anchoring only to the extent such stopping and anchoring are required by the U.S. Coast Guard; rendered necessary by force majeure or distress; or made for the purpose of rendering assistance to persons, ships, or aircraft in danger or distress. This exemption does not apply to the passage of an ocean-going vessel that engages in any of the prejudicial activities specified in United Nations Convention on the Law of the Seas (UNCLOS) 1982, Article 19, subpart 2. Further, notwithstanding any Coast Guard mandated stops or stops due to force majeure or the rendering of assistance, this exemption does not apply to a vessel that was otherwise scheduled or intended to enter California internal or estuarine waters or call at a port, roadstead or terminal facility.

(B) Auxiliary engines on-board ocean-going vessels owned or operated by any branch of local, state, federal government, or by a foreign government, when such vessels are operated on government non-commercial service. However, such vessels are encouraged to act in a manner consistent, so far as is reasonable and practicable, with this section.

(C) Steamships while berthed at a California port.

(D) Auxiliary engines while such engines are operating primarily on liquefied natural gas or compressed natural gas.

(c) *Definitions.*

For purposes of this section, the definitions in Health and Safety Code sections 39010 through 39060 shall apply except as otherwise specified in this section:

(1) "Alternative Control Technologies" means technologies, techniques, or measures that reduce the emissions of NOx and PM from an auxiliary diesel engine other than shutting down the engine.

(2) "Auxiliary Engine" means an engine on an ocean-going vessel designed primarily to provide power for uses other than propulsion, except that all diesel-electric engines shall be considered "auxiliary diesel engines" for purposes of this section.

(3) "Baseline Fleet Emissions" means the total emissions from all vessels in a fleet during all berthing times in a calendar year or other specified time period. For purposes of calculating the baseline fleet emissions, the auxiliary engines on the vessels in the fleet shall be assumed to use marine diesel fuel while at berth.

(4) "Berthing Time" means the time period that begins when the vessel is first tied to the berth and ends when the vessel is untied from the berth.

(5) "California Ports" means:

(A) The Port of Hueneme, the Port of Los Angeles (POLA) and Port of Long Beach (POLB), the Port of Oakland, the Port of San Diego, and the Port of San Francisco;

(B) For purposes of this section, POLA and POLB are treated as one port.

(6) "Container Vessel" means a self-propelled ocean-going vessel constructed or adapted primarily to carry uniform-sized ocean freight containers.

(7) "Diesel Engine" means an internal combustion, compression-ignition (CI) engine with operating characteristics significantly similar to the theoretical diesel combustion cycle. The regulation of power by controlling fuel supply in lieu of a throttle is indicative of a compression ignition engine.

(8) "Diesel-Electric Engine" means a diesel engine connected to a generator that is used as a source of electricity for propulsion or other uses.

(9) "Diesel Particulate Matter" means the particles found in the exhaust of diesel engines, which may agglomerate and adsorb other species to form structures of complex physical and chemical properties.

(10) "Distributed Generation" shall have the same meaning as that term is defined in title 17, CCR, section 94202.

(11) "Docked at the Berth" means the state of being tied to a berth.

(12) "Emergency Event" means the period of time during which any of the following events occurs; the emergency event begins when such an event begins and ends when the event is over:

(A) Any situation arising from a sudden and reasonably unforeseen event beyond the control of the master that threatens the safety of the vessel;

(B) The utility serving the port states that electrical power will be temporarily unavailable as a result of equipment failure; or

(C) The electrical system at the terminal cannot provide electrical power as a result of equipment failure; or

(13) "Executive Officer" means the executive officer of the Air Resources Board (ARB), or his or her designee.

(14) "Fleet" means all container, passenger, and refrigerated cargo (reefer) vessels, visiting a specific California port, which are owned or operated under the direct control of the same person. Direct control includes, but is not limited to, vessels that are operated under a contract, lease, or other arrangement with a third-party for the third-party to operate the vessel. For the purposes of this section, a person shall be deemed to have separate fleets for each California port visited. For example, if a person owns or operates vessels that visit both the Port of Los Angeles and Port of Oakland, that person is deemed to have two fleets, one a "POLA-based fleet" and the other a "Port of Oakland-based fleet."

(15) "IMO" means the International Maritime Organization.

(16) "Landlord Port" means a California port that leases the port's real property to a person(s).

(17) "Master" means the person who operates an ocean-going vessel or is otherwise in charge of the vessel's operations.

(18) "Ocean-Going Vessel" means a commercial, government, or military vessel meeting any one of the following criteria:

(A) A vessel greater than or equal to 400 feet in length overall (LOA) as defined in 50 CFR § 679.2, as adopted June 19, 1996;

(B) A vessel greater than or equal to 10,000 gross tons (GT ITC) pursuant to the convention measurement (international system) as defined in 46 CFR § 69.51-.61, as adopted September 12, 1989; or

(C) A vessel propelled by a marine compression ignition engine with a per-cylinder displacement of greater than or equal to 30 liters.

For the purposes of this section, "ocean-going vessel" will be used interchangeably with the term "vessel."

(19) "Operate" means steering or otherwise running the vessel or its functions while the vessel is underway, moored, anchored, or at berth.

(20) "Operate an Auxiliary Diesel Engine" means running or idling an auxiliary diesel engine such that it is producing mechanical work or electricity or is otherwise consuming fuel.

(21) "Own" means having all the incidents of ownership, including the legal title, of a vessel whether or not that person leads, rents, or pledges the vessel; having or being entitled to the possession of a vessel as the purchaser under a conditional sale contract; or being the mortgagor of a vessel.

(22) "Oxides of Nitrogen" means compounds of nitric oxide (NO), nitrogen dioxide (NO_2), and other oxides of nitrogen, which are typically created during combustion processes and are major contributors to smog formation and acid deposition.

(23) "Particulate Matter" means any airborne finely divided material, except uncombined water, which exists as a liquid or solid at standard conditions (e.g., dust, smoke, mist, fumes, or smog).

(24) "Passenger Vessel" means a self-propelled vessel constructed or adapted primarily to carry people.

(25) "Person" includes all of the following:

(A) Any person, firm, association, organization, partnership, business trust, corporation, limited liability company, or company;

(B) Any state or local governmental agency or public district, or any officer or employee thereof;

(C) The United States or its agencies, to the extent authorized by federal law.

(26) "Post-Baseline Fleet Emissions" means the total emissions from all vessels in a fleet after the application of alternative control technologies during all berthing times in a calendar year or other specified time period. For purposes of calculating the baseline fleet emissions, the auxiliary engines on the vessels in the fleet shall be assumed to use marine diesel fuel while at berth.

(27) "Refrigerated Cargo (or Reefer) Vessel" means a self-propelled vessel constructed or adapted primarily to carry refrigerated cargo. Reefer vessels include vessels where the cargo may be stored in large refrigerated rooms within the vessel or vessels that carry exclusively refrigerated cargo containers.

(28) "Responsible Official" means the individual(s) with the authority to certify that all vessels in a fleet comply with applicable requirements of this regulation.

(29) "Shore power" refers to electrical power being provided by either the local utility or by distributed generation.

(30) "Steamship" means a self-propelled vessel in which the primary propulsion and electrical power are provided by steam boilers.

(31) "Synchronous Power Transfer" means the synchronized switchover in vessel-based power to shore-based power without a loss in power during such transfer.

(32) "Terminal" means a facility consisting of wharves, piers, docks and other berthing locations and adjacent storage, which are used primarily for loading and unloading of cargo or material from vessels or the temporary storage of this cargo or material on-site.

(33) "Terminal Operator" means a person that leases terminal property from a port for the purpose of loading and unloading of cargo or material from vessels or the temporary storage of this cargo or material on-site.

(34) "Utility" shall have the same meaning and be used interchangeably with the term "Electric Utility" as defined in Public Resources Code section 28105.

(35) "Verified Emission Control Strategy" means an emission control strategy that has been verified pursuant to the "Verification Procedure

for In-Use Strategies to Control Emissions from Diesel Engines" in title 13, California Code of Regulations, commencing with section 2700, which is incorporated herein by reference.

(36) "Visit" means the time period that begins when an ocean-going vessel initially ties to a berth (the beginning of the visit) and ends when it casts off the lines (the end of the visit) at a berth in a California port. Separate and sequential visits shall collectively be deemed a single visit when a vessel ties to two or more berths at the same California port and the time interval between leaving one berth and tying to another berth in the same port is less than two hours.

(d) Vessel In-Use Operational Requirements.

(1) Limits on Hours and Other Aspects of Operation for Auxiliary Diesel Engines on Container, Passenger, and Refrigerated Cargo (Reefer) Vessels.

(A) Except as provided in subsection (d)(2), beginning January 1, 2014, no less than 50 percent of a fleet's visits to a California port in a calendar quarter, rounded to the nearest whole visit, shall meet the following limits on the number of hours auxiliary diesel engines on such vessels may be operated at berth:

1. Three hours total per visit, provided the visiting vessel uses a synchronous power transfer process to change from vessel-based power to shore-based power; or

2. Five hours total per visit, provided the visiting vessel does not use a synchronous power transfer process to change from vessel-based power to shore-based power.

For example, if a person's fleet makes 10 visits to a California port in a calendar quarter, the auxiliary diesel engines on vessels in at least 5 of those visits shall be operated no more than a combined 3 or 5 hours total, depending on whether a synchronous power transfer is used. The 3- and 5-hour limit applies to the combined operating time for all auxiliary diesel engines used in a vessel visit, rather than on a per-engine basis.

(B) Except as provided in subsection (d)(2), beginning January 1, 2020, no less than 80 percent of a fleet's visits to a California port in a calendar quarter, rounded to the nearest whole visit, shall meet the following limits on the number of hours auxiliary diesel engines on such vessels may be operated at berth:

1. Three hours total per visit, provided the visiting vessel uses a synchronous power transfer process to change from vessel-based power to shore-based power; or

2. Five hours total per visit, provided the visiting vessel does not use a synchronous power transfer process to change from vessel-based power to shore-based power.

For example, if a person's fleet makes 10 visits to a California port in a calendar quarter, the auxiliary diesel engines on vessels in at least 5 of those visits shall be operated no more than a combined 3 or 5 hours total, depending on whether a synchronous power transfer is used. The 3- and 5-hour limit applies to the combined operating time for all auxiliary diesel engines used in a vessel visit, rather than on a per-engine basis.

(C) Compliance with the requirements in subsection (d)(1)(A) and (d)(1)(B) shall be determined quarterly for the periods specified as follows:

1. January 1 through March 31, inclusive;

2. April 1 through June 30, inclusive;

3. July 1 through September 30, inclusive; and

4. October 1 through December 31, inclusive.

(D) Except as otherwise specified in subsection (d)(1)(F), the requirements of subsection (d)(1)(A) and (d)(1)(B) do not apply to:

1. A fleet comprised solely of container or reefer vessels that visits a California port fewer than 25 times total in a calendar year; and

2. A fleet comprised solely of passenger vessels that visits a California port fewer than 5 times total in a calendar year.

(E) No person shall sell, supply, offer to supply, or purchase electrical power for use on a vessel during a visit in lieu of using the on-board auxiliary diesel engines, unless such electrical power is either supplied by the local utility or is otherwise generated by equipment that meet the following emission standards:

1. NOx emissions no greater than 0.03 gram per kilowatt-hour (g/kW-hr);

2. PM emissions equivalent to the combustion of natural gas with a fuel sulfur content of no more than one grain per 100 standard cubic foot;

3. CO_2 emissions shall be no greater than 500 g/kW-hr; and

4. Ammonia emissions no greater than five parts per million on a dry volume basis (ppmdv), if selective catalytic reduction is used.

(F) Notwithstanding the requirements specified in subsection (d)(1)(A) and (d)(1)(B), any ocean-going vessel equipped to receive shore power that visits a berth equipped to provide compatible shore power shall utilize the shore power during every visit to that berth. This requirement shall not apply under the following circumstances:

1. The master of the vessel reasonably and actually determines that an emergency event, as defined in subsection (c)(12)(A), is in effect and the use of shore power during the emergency event would endanger the vessel's safety. Shore power shall be used for the remainder of the visit once the master determines that the emergency event no longer exists;

2. An emergency event, as defined in subsection (c)(12)(B) or (c)(12)(C), is in effect. Shore power shall be used for the remainder of the visit once the emergency event is no longer in effect; or

3. The California Independent System Operator (CAISO) has declared a Stage 3 emergency and the utility providing electrical power to the port is requesting the terminal where the vessel is located to reduce the use of grid-based electrical power. Shore power shall be used for the remainder of the visit once CAISO declares the Stage 3 emergency is over.

(2) *Emissions Reduction Option.*

The purpose of this provision is to allow any person the option of complying with the requirements of this subsection (d)(2) in lieu of meeting the requirements of subsection (d)(1).

Requirements.

(A) For fleets visiting terminals that are providing electrical power from the utility's electrical grid, the owner or operator of the fleets shall comply with the following schedule:

1. For the quarter beginning on January 1, 2014, and each subsequent quarter through December 31, 2019, inclusive, the NOx and PM emissions at berth from the fleet's auxiliary engines must be reduced by 50 percent from the baseline fleet emissions.

2. For the quarter beginning on January 1, 2020, and each subsequent quarter thereafter, the NOx and PM emissions at berth from the fleet's auxiliary engines must be reduced by 80 percent from the baseline fleet emissions.

(B) For fleets visiting terminals that are providing electrical power from sources that are not part of an utility's electrical grid, or alternative control technologies are used to reduce the emissions of the fleet, the owner or operator of the fleet shall comply with the following schedule:

1. For the quarter beginning on January 1, 2010, and each subsequent quarter through December 31, 2011, inclusive, the NOx and PM emissions at berth from the fleet's auxiliary engines must be reduced by 20 percent from the baseline fleet emissions.

2. For the quarter beginning on January 1, 2012, and each subsequent quarter through December 31, 2013, inclusive, the NOx and PM emissions at berth from the fleet's auxiliary engines must be reduced by 40 percent from the baseline fleet emissions.

3. For the quarter beginning on January 1, 2014, and each subsequent quarter through December 31, 2015, inclusive, the NOx and PM emissions at berth from the fleet's auxiliary engines must be reduced by 60 percent from the baseline fleet emissions.

4. For the quarter beginning on January 1, 2016, and each subsequent quarter thereafter, the NOx and PM emissions from the fleet's auxiliary engines must be reduced by 80 percent from the baseline fleet emissions.

(C) For fleets visiting terminals that are using a combination of electrical power from the utility grid and electrical power from sources that are not part of an utility's electrical grid, or alternative control technologies, the following schedule applies:

1. For the quarter beginning on January 1, 2012, and each subsequent quarter through December 31, 2013, inclusive, the NOx and PM emissions at berth from the fleet's auxiliary engines must be reduced by 20 percent from the baseline fleet emissions.

2. For the quarter beginning on January 1, 2014, and each subsequent quarter through December 31, 2019, inclusive, the NOx and PM emissions from the fleet's auxiliary engines must be reduced by 50 percent from the baseline fleet emissions.

3. For the quarter beginning on January 1, 2020, and each subsequent quarter thereafter, the NOx and PM emissions from the fleet's auxiliary engines must be reduced by 80 percent from the baseline fleet emissions.

(D) Compliance with the requirements of subsection (d)(2)(A), (d)(2)(B), and (d)(2)(C) shall be determined quarterly for the periods specified as follows:

1. January 1 through March 31, inclusive;

2. April 1 through June 30, inclusive;

3. July 1 through September 30, inclusive; and

4. October 1 through December 31, inclusive.

(E) No person shall sell, supply, offer to supply, or purchase electrical power for use on a vessel during a visit in lieu of using the on-board auxiliary diesel engines, unless such electrical power is either be supplied by the local utility or is otherwise generated by equipment that meet the following emission:

1. NOx Emissions.

   a. Up to and including December 31, 2013, the NOx emissions shall be no greater than 2 g/kW-hr at any time; and

b. Beginning January 1, 2014, the NOx emissions shall be no greater than 0.2 g/kW-hr at any time;

2. PM emissions shall be no greater than the PM emissions from combustion of natural gas with a fuel sulfur content of no more than one grain per 100 standard cubic foot;

3. CO_2 emissions shall be no greater than 500 g/kW-hr; and

4. Ammonia emissions shall be no greater than five ppmdv if selective catalytic reduction is used.

(e) Exemptions to the Three-Hour or Five-Hour Limited Auxiliary Engine Operation Requirement in Subsection (d)(1)(A)(1), (d)(1)(A)(2), (d)(1)(B)(1) and (d)(1)(B)(2).

(1) Emergency Event.

All of the following requirements apply to claimed exemptions based on emergency events:

(A) If the master of the vessel reasonably and actually determines that an emergency event, as defined subsection (c)(12), occurs during the vessel's visit to a California port, the master of the vessel may operate the vessel's auxiliary engines during the emergency event;

(B) The master shall not operate the vessel's auxiliary engines for more than one hour beyond the time when the master receives notification that the emergency event is over, determines that the emergency event is over, or should have known the emergency event is over; and

(C) The provisions of paragraph (B) above notwithstanding, the master may continue to operate the auxiliary engines for no more than five hours if the master receives notification that the emergency event is over, determines that the emergency event is over, or should have known the emergency event is over and the vessel is scheduled to leave port within five hours.

(2) Delays Caused By U.S. Coast Guard or Department of Homeland Security Inspections.

The Executive Officer may extend the three-hour/five-hour operational requirement in subsection (d)(1)(A) and (d)(1)(B) if the following criteria are met:

(A) The initial inspection and clearance of the vessel by the Department of Homeland Security exceeds one hour. The time extension granted shall be commensurate with the excess time necessary for inspection and clearance; or

(B) After the auxiliary engines have been put back into service pending departure from the berth, the scheduled departure of the vessel has been delayed by the United States (U.S.) Coast Guard or the Department of Homeland Security.

(f) *Calculations for Emissions Reduction Option in Subsection (d)(2).*

(1) For the purposes of subsection (d)(2)(A), (d)(2)(B), and (d)(2)(C), the percent emission reduction shall be calculated as follows:

Percent Reduction = (BFE – PBFE) / BFE

Where,

The baseline fleet and post-baseline fleet emissions are calculated as follows:

(A) Baseline Fleet Emissions (BFE).

The baseline fleet emissions of NOx and PM shall be calculated using the following formula:

Baseline Fleet Emissions = $\sum$ (emission rate x average berthing time x power requirement x visits)

Where:

"Emission rate" for each auxiliary engine is determined pursuant to subsection (f)(2);

"Average berthing time" for each vessel is determined for the applicable period specified in subsection (d)(2)(D);

"Power requirements" means the electrical power requirement for each vessel as determined pursuant to subsection (f)(3);

"Visits" means the total number of visits by the vessel during the applicable period specified in subsection (d)(2)(D); and

"Σ" means the summation over the entire fleet subject to the emission reduction option.

(B) Post-Baseline Fleet Emissions (PBFE).

The post-baseline fleet emissions of NOx and PM shall be calculated using the following formula:

Post-Baseline Fleet Emissions = Σ (emission rate x average berthing time x power requirement x visits x control factor)

Where:

"Emission rate" for each auxiliary engine is determined pursuant to subsection (f)(2);

"Average berthing time" for each vessel is determined for the applicable period specified in subsection (d)(2)(D);

"Power requirements" means the electrical power requirement for each vessel as determined pursuant to subsection (f)(3);

"Visits" means the total number of visits by the vessel during the applicable period specified in subsection (d)(2)(D);

"Control factor" means the applicable control factor specified in subsection (f)(4); and

"Σ" means the summation over the entire fleet subject to the emission reduction option.

(2) A person complying with the requirements of subsection (d)(2) may choose any of the following emissions rates for use in the calculations specified in subsection (f)(1)(A) and (f)(1)(B):

(A) Results from emission measurements for similar auxiliary diesel engines that are used to satisfy a marine engine standard, including U.S. Environmental Protection Agency (EPA) emission standards for marine engines (40 CFR Part 94), and the International Convention for the Prevention of Pollution from

Ships, 1973, as modified by the Protocol of 1978 (MARPOL 73/78), both of which are incorporated herein by reference;

(B) Emission measurements approved by the Executive Officer and using the test methods specified in subsection (f)(4)(B)(3); or

(C) In lieu of test data measured pursuant to paragraph (A) or (B) above, the following emission rates may be used as default values:

1. 13.9 g/kW-hr for NOx.

2. 0.38 g/kW-hr for PM if 0.11 to 0.5 percent sulfur marine gas oil is used as a fuel.

3. 0.25 g/kW-hr for PM if 0.10 or less sulfur content marine gas oil is used as a fuel.

(3) Power Requirements.

(A) The following values in Table 1 may be used as default values for power requirements:

Table 1.

Ship Category	Ship Size / Type	Default Power Requirement (kW)
Container Vessel	<1000 TEU	1,000
	1,000-1,999 TEU	1,300
	2,000-2,999 TEU	1,600
	3,000-3,999 TEU	1,900
	4,000-4,999 TEU	2,200
	5,000-5,999 TEU	2,300
	6,000-6,999 TEU	2,500
	7,000-7,999 TEU	2,900
	8,000-9,999 TEU	3,300
	10,000-12,000 TEU	3,700
Passenger Vessel		No Default Value – Use Actual Load
Reefer	Break Bulk	1,300
	Fully Containerized	3,300

TEU = twenty-foot equivalent unit.
kW = kilowatt

(B) In lieu of the default values above, the fleet operator may, with adequate supporting documentation, use the following:

1. The actual shore power usage, on a monthly basis, rounded to the nearest whole kW-hrs, of the vessels in the fleet utilizing shore power, or

2. The actual on-board power usage, on a monthly basis, rounded to the nearest whole kW-hrs, of the vessels in the fleet utilizing alternative control technologies.

(4) Control Factors.

(A) The emissions from vessels using grid power in lieu of the vessel's auxiliary engines when the vessels are at berth are presumed to be reduced by 90 percent.

(B) No control efficiencies for alternative control technologies shall be used to comply with the requirements of this provision unless the control efficiencies are calculated or measured as follows:

1. The control efficiencies shall be based on an emission test protocol that is approved by the Executive Officer prior to conducting the emission measurements;

2. The results of the emission measurements conducted pursuant to paragraph 1 above are approved by the Executive Officer; and

3. Emission measurements are conducted using the following test methods:

a. NOx and CO_2 shall be measured using California Air Resources Board (CARB) Test Method 100, dated July 1997, which is incorporated herein by reference, or equivalent district-approved test method;

b. Diesel PM shall be measured using ISO 8178 Test Procedures: ISO 8178-1: 1996(E) ("ISO 8178 Part 1"); ISO 8178-2:1996(E) ("ISO 8178 Part 2"); and ISO 8178-4: 1996(E) ("ISO 8178 Part 4"), all of which are incorporated herein by reference; and

c. Ammonia slip shall be measured using the Bay Area Air Quality Management District Source Test Procedure

ST-1B, Ammonia Integrated Sampling, dated January 1982, which is incorporated herein by reference, or other equivalent district approved test method.

d. The sulfur content of fuels shall be determined pursuant to International Standard ISO 8754 (as adopted in 2003), which is incorporated herein by reference.

(C) Results from emission measurements from a verified emission control strategy may be used in conjunction with engine emission information.

(D) The Executive Officer may request periodic emission testing or other types of monitoring to verify the proper operation of alternative control technologies or to verify the emission rate of an auxiliary engine.

1. At a minimum, emission control technologies shall be tested as follows and the results of such testing provided to the Executive Officer within 30 days of the testing:

   a. Shore-based systems shall be tested annually to demonstrate the overall percentage of emission reduction being achieved.

   b. Catalyst based air pollution control systems installed on vessels shall be tested after every 1,000 hours of operation to determine the overall percentage of emission reduction being achieved.

   c. If Selective Catalytic Reduction (SCR) is used as a control technology, the emissions of ammonia shall also be measured at the same time the NOx emissions are being measured.

2. The Executive Officer may modify the testing frequency as he/she deems appropriate.

(g) *Terminal Plan Requirements.*

(1) A terminal that receives more than 50 vessel visits in 2008 shall submit a plan for the Executive Officer's approval that discusses how the terminal will accommodate the vessels that will visit the terminal who are subject to subsection (d)(1) and (d)(2). The terminal shall submit the plan and subsequent updates to the plan according to the schedule below (Table 2). The plan updates shall address any contingencies

that may be necessary for the vessels to meet the requirements of subsection (d)(1)and (d)(2) by the applicable dates.

Table 2.

Vessel Compliance Option	Initial Terminal Plan Due Date	Subsequent Terminal Plan Updates
Grid-Based Shore Power: (d)(1) and (d)(2)(A)	July 1, 2009	July 1, 2013 July 1, 2019
Alternative Control Technologies to Grid-Based Shore Power: (d)(2)(B)	July 1, 2009	July 1, 2011 July 1, 2013 July 1, 2015
Combination of Grid-Based Shore Power and Alternative Control Technologies: (d)(2)(C)	July 1, 2009	July 1, 2011 July 1, 2013 July 1, 2015 July 1, 2019

(2) Plan Requirements for Grid-Based Shore Power.

(A) Specify the schedule for implementing infrastructure modifications, including the following:

1. Utility infrastructure improvements, if any, outside the port boundary;

2. Improvements to port infrastructure; and

3. Major infrastructure improvements to terminal.

(B) Identification of existing berths to be modified or new berths to be constructed that will satisfy the requirements of subsection (d)(1).

(3) Plan Requirements for Alternative Control Technologies.

(A) Description of the approach that will be used to reduce in-berth vessel emissions, including whether the approach is a vessel-based approach or shore-based approach;

(B) Identification and description of equipment;

(C) Berth(s) where the equipment will be used;

(D) Specific vessels affected by the technology; and

(E) Estimate of the expected reductions in NOx and PM emissions from vessels using the technology, including documentation supporting the anticipated reductions.

(4) Plan Requirements for a Combination of Grid-Based Shore Power and Alternative Control Technologies.

(A) Identification of which berths will implement grid-based shore power and which berths will implement alternative control technologies

(B) For berths implementing shore-based grid power, the plan must contain the information specified in subsection (g)(2).

(C) For berths implementing alternative control technologies, the plan shall contain the information specified in subsection (g)(3).

(5) A port may submit terminal plans required under subsection (g)(1) on behalf of the terminals located at that port.

(h) *Reporting and Recordkeeping Requirements.*

(1) Reporting and Recordkeeping Requirements for Persons that Comply with Subsection (d)(1).

(A) The Responsible Official shall provide the following reports to the Executive Officer:

1. A vessel fleet plan, due to the Executive Officer by July 1, 2013, and an updated plan by July 1, 2019, which includes a listing of the vessels that would be affected by the requirements specified in subsection (d)(1) and the description of the ability of each vessel to use shore power.

   The vessel fleet plan shall list the vessels that are able to shut down the vessel's auxiliary engines and use shore power, along with the related information as follows:

   a. Name of the vessel, Lloyd's number for the vessel, and vessel category (container, passenger, or reefer); and

   b. The port(s) each vessel(s) is expected to visit.

2. An annual statement of compliance pursuant to subsection (d)(1) and (d)(2).

   a. The initial annual statement of compliance is due to the Executive Officer by March 1, 2015. This statement is for the 2014 calendar year. Thereafter, the annual statement is due to the Executive Officer by March 1 of each year, certifying compliance with the requirements for the previous calendar year.

   b. The annual statement of compliance shall include the following:

      i. A statement signed by the Responsible Official that the requirements specified in subsection (d)(1) or (d)(2) have been met.

      ii. Visit-related information for all vessels within a fleet that visited a California port. The list shall include the following information for each vessel:

         I. Current name of the vessel;
         II. Lloyd's number for the vessel;
         III. Vessel type (cargo, passenger, reefer); and
         IV. Visits, by port and terminal, where the auxiliary engines were shut down;

      iii. The information submitted pursuant to paragraph 2.b.ii above shall be reported for the following periods:

         I. January 1 through March 31, inclusive;
         II. April 1 through June 30, inclusive;
         III. July 1 through September 30, inclusive; and
         IV. October 1 through December 31, inclusive.

(B) Recordkeeping.

1. The following records shall be kept at a central location by the vessel operator. This information shall be supplied to the Executive Officer within 30 days of a request from ARB inspectors or staff.

   a. A logbook that records, for each visit, the dates, times, and other information as specified below:

i. When the vessel initially tied to the berth and when the vessel cast-off the tie lines;

ii. When the Department of Homeland Security released the vessel;

iii. When the auxiliary engines were initially shut down and subsequently restarted;

iv. Whether departure from the berth was delayed by the U.S. Coast Guard or other federal agency and identification of the agency that caused the delay;

v. If an emergency event occurred, a description of that emergency event;

vi. If the vessel could not use shore power as a result of the CAISO declaring a stage 3 emergency, and

vii. If a vessel could not use shore power as a result of equipment failure aboard the vessel

b. Copies of all current U.S. Department of Homeland Security Bureau of Customs and Border Protection "Vessel Entrance or Clearance Statement" documents (CBP Form 1300, version 02/02), which is incorporated herein by reference, if the vessel operator or owner is claiming an exemption pursuant to subsection (e)(2)(A) or (e)(2)(B).

2. All records required pursuant to this provision shall be retained for a minimum of five years.

(2) Reporting and Recordkeeping Requirements for Persons Opting to Comply with the Emissions Reduction Option in Subsection (d)(2).

(A) The Responsible Official shall provide the following reports to the Executive Officer:

1. A vessel fleet plan, due to the Executive Officer by the dates shown in Table 3 below:

Table 3.

Compliance Option	Initial Vessel Fleet Plan	Subsequent Submittal Due Dates
Grid-Based Shore Power: (d)(2)(A)	July 1, 2013	July 1, 2019
Alternative Control Technologies to Grid-Based Shore Power: (d)(2)(B)	July 1, 2009	July 1, 2011 July 1, 2013 July 1, 2015
Combination of Grid-Based Shore Power and Alternative Control Technologies: (d)(2)(C)	July 1, 2011	July 1, 2013 July 1, 2019

The vessel fleet plan shall include the following items:

a. List of the vessels included in the company's fleet; Lloyd's number for each vessel, vessel category (cargo, passenger, reefer), average number of reefer containers carried by the vessel over the calendar year (container vessels only), and power requirement for each vessel (passenger and reefer vessels); and

b. Identify the potential alternative control techniques that may be used to achieve the requirements specified in subsection (d)(2). For each control technique, specify the following:

   i. The vessels that would be affected by the technique;

   ii. The status of implementation of the alternative control technique; and

   iii. The basis used in determining the expected emission reduction, including submittal of any emission testing or other documentation.

2. An annual statement of compliance.

   a. The initial annual statement of compliance is due to the Executive Officer by the dates in Table 4 below:

Table 4.

Compliance Option	Initial Submittal of Annual Statement of Compliance
Grid-Based Shore Power: (d)(2)(A)	March 1, 2015
Alternative Control Technologies to Grid-Based Shore Power: (d)(2)(B)	March 1, 2011
Combination of Grid-Based Shore Power and Alternative Control technologies: (d)(2)(C)	March 1, 2013

Thereafter, the annual compliance statement is due to the Executive Officer by March 1 of each year, certifying compliance with the requirements for the previous year.

b. The following items, applicable to the calendar year in question, should be included with the statement of compliance:

i. A statement signed by the Responsible Official indicating that the NOx and PM emission reductions specified by (d)(2) have been achieved;

ii. The calculated NOx and PM baseline and post-baseline emissions for each fleet, on a quarterly basis, as specified in (d)(2)(D). Include each vessel's contribution to the fleet's baseline and post-baseline emissions; and

iii. Description of the technique(s) used, including alternative controls technology (or technologies), achievable emission reductions, and supporting documentation (e.g., source test results or verification documentation). For subsequent statements of compliance, the supporting documents can be referenced.

(B) Recordkeeping.

1. The following records shall be kept at a central location by the master and the fleet vessel operator. This information shall be

supplied to the Executive Officer within 30 days of a request from ARB staff.

For each calendar year of vessel activity, a quarterly summary of emissions that demonstrates compliance with the applicable emission reduction (2010, 2012, 2014, or 2016), which includes the following:

a. The fleet's baseline and post-baseline levels for NOx and PM emissions; and

b. Each vessel's contribution to fleet's baseline and post-baseline NOx and PM emissions, including the following information:

   i. Name of each vessel;

   ii. Lloyd's number for each vessel;

   iii. Fuel type and average sulfur content of fuel for each vessel;

   iv. NOx and PM emissions for each vessel;

   v. Average hotelling time for each vessel;

   vi. Power requirements for each vessel while at berth;

   vii. For container vessels, the number of reefer containers imported and exported for each container vessel;

   viii. Total visits to each California port made by the vessel;

   ix. Technology used to reduce emissions and associated control factor used; and

   x. Any equipment failure aboard a vessel that prevented the vessel from using the emissions reduction technology

2. Records made pursuant to paragraph (2)(B) above shall be kept for a minimum of five years.

(3) Reporting and Recordkeeping Requirements for Ports and Terminals.

(A) Affected ports shall provide wharfinger information to the Executive Officer annually, beginning with the wharfinger information for calendar year 2010.

1. This information shall be provided to the Executive Officer no later than April 1 of the following year.

2. At a minimum, the wharfinger information shall include for each vessel visiting the port:

a. Name of the vessel;

b. Vessel type;

c. Company operating the vessel;

d. Lloyd's number for each vessel;

e. Berth used by the vessel; and

f. Date(s) and time the vessel was initially tied to the berth and subsequently released from the berth.

(B) The terminal operator shall keep the following records. These records shall be supplied to the Executive Officer within 30 days of a request from ARB staff:

1. Electricity usage for shore power:

a. Monthly utility billing statements that separately identify electricity supplied for shore power;

b. Episodes of electrical service interruption by local utility company, as confirmed and documented by local utility company; and

c. For distributed generation, monthly records that contain the following:

i. Names of vessels serviced;
ii. Location of vessels serviced, by berth;
iii. Date and time of use; and
iv. Power, in megawatts, supplied to the vessels.

2. Date, time, and description of equipment failure that affected the ability of vessels to turn off their auxiliary engines or use alternative control technologies to reduce emissions pursuant to (d)(2).

3. Record of each vessel that did not operate its auxiliary engines while the vessel was docked at the terminal:

   a. Name of vessel; and

   b. Date and time each vessel was initially tied to the terminal.

4. Records made pursuant to paragraph (3)(B) above shall be kept for five years.

(4) Electronic submittals of records and other information required under this section may be approved by the Executive Officer upon request, provided such electronic submittals use digital signatures that meet the requirements specified in Government Code section 16.5. Notwithstanding the approved submittal of electronic records, the Executive Officer may request the submittal of a hard copy of any electronic submittal.

(i) *Violations.*

(1) Except as otherwise specified in this subsection, any person who is subject to this section and commits a violation of any provision, prohibition, limit, standard, criteria, or requirement in this section is subject to the penalties, injunctive relief, and other remedies specified in Health and Safety Code section 42400 et seq., other applicable sections in the Health and Safety Code; and other applicable provisions as provided under California law for each violation. Nothing in this section shall be construed to limit or otherwise affect any applicable penalties or other remedies available under federal law.

(2) Except as otherwise specified in this subsection, any failure to meet any provision, prohibition, limit, standard, criteria, or requirement in this section, including but not limited to the applicable emission limits for supplied shore power and hours of engine operation limits, shall constitute a single, separate violation of this section for each hour that a person operates the auxiliary diesel engine until such provision, prohibition, limit, standard, criteria, or requirement has been met.

(3) A violation of the recordkeeping and reporting requirements in this section shall constitute a single, separate violation of this section for

each day that the applicable recordkeeping or reporting requirement has not been met.

(j) *Severability.*

If any subsection, paragraph, subparagraph, sentence, clause, phrase, or portion of this regulation is, for any reason, held invalid, unconstitutional, or unenforceable by any court of competent jurisdiction, such portion shall be deemed as a separate, distinct, and independent provision, and such holding shall not affect the validity of the remaining portions of the regulation.

NOTE: Authority cited: Sections 38560, 38560.5, 39600, 39601, 41511, 43013, and 43018, Health and Safety Code. Reference: Sections 38560, 38560.5, 39000, 39001, 39515, 39516, 41510, 41511, 43013, and 43018, Health and Safety Code; and *Western Oil and Gas Ass'n v. Orange Country Air Pollution Control District*, (1975) 14 Cal.3d 411, 121 Cal.Rptr. 249.

PROPOSED REGULATION ORDER

AIRBORNE TOXIC CONTROL MEASURE FOR AUXILIARY DIESEL ENGINES OPERATED ON OCEAN-GOING VESSELS AT-BERTH IN A CALIFORNIA PORT

Adopt new section 93118.3, title 17, chapter 1, subchapter 7.5, California Code of Regulations (CCR), to read as follows:

(Note: The entire text of section 93118.3 is new language.):

Section 93118.3. Airborne Toxic Control Measure for Auxiliary Diesel Engines Operated on Ocean-Going Vessels At-Berth in a California Port.

(a) *Purpose.*

The purpose of this section is to reduce oxides of nitrogen (NOx) and diesel particulate matter (PM) emissions from the operation of auxiliary engines on container ships, passenger ships, and refrigerated cargo ships while these vessels are docked at berth at a California port. This section reduces emissions by limiting the time during which auxiliary diesel engines are operated on the regulated vessels while such vessels are docked at-berth in a California port, as well as by applying other requirements. This section implements provisions of the Goods Movement Emission Reduction Plan, adopted by the Air Resources Board (ARB) in April 2006, to reduce emissions and health risk from ports and the movement of goods in California. This section also helps achieve the goals specified in the California Global Warming Solutions Act of 2006, established under California law by Assembly Bill 32 (Stats. 2006, ch. 488) and set forth in Health and Safety Code § 38500 et seq.

(b) Applicability and General Exemptions.

(1) Except as provided in this subsection (b), this section applies to any person who owns, operates, charters, rents, or leases any U.S. or foreign-flagged container ship, passenger ship, or refrigerated cargo ship that visits a California port. In addition, this section also applies to any person who owns or operates a port or terminal located at a port where container, passenger, or refrigerated cargo vessels visit.

(2) Nothing in this section shall be construed to amend, repeal, modify, or change in any way any applicable U.S. Coast Guard requirements. Any person subject to this section shall be responsible for ensuring compliance with both U.S. Coast Guard regulations and the

requirements of this section, including but not limited to, obtaining any necessary approvals, exemptions, or orders from the U.S. Coast Guard.

(3) The requirements of this section do not apply to:

(A) Ocean-going vessel voyages that are comprised of continuous and expeditious navigation through any of the Regulated California Waters for the purpose of traversing such bodies of water without entering California internal or estuarine waters or calling at a port, roadstead, or terminal facility. "Continuous and expeditious navigation" includes stopping and anchoring only to the extent such stopping and anchoring are required by the U.S. Coast Guard; rendered necessary by force majeure or distress; or made for the purpose of rendering assistance to persons, ships, or aircraft in danger or distress. This exemption does not apply to the passage of an ocean-going vessel that engages in any of the prejudicial activities specified in United Nations Convention on the Law of the Seas (UNCLOS) 1982, Article 19, subpart 2. Further, notwithstanding any Coast Guard mandated stops or stops due to force majeure or the rendering of assistance, this exemption does not apply to a vessel that was otherwise scheduled or intended to enter California internal or estuarine waters or call at a port, roadstead or terminal facility.

(B) Auxiliary engines on-board ocean-going vessels owned or operated by any branch of local, state, federal government, or by a foreign government, when such vessels are operated on government non-commercial service. However, such vessels are encouraged to act in a manner consistent, so far as is reasonable and practicable, with this section.

(C) Steamships while berthed at a California port.

(D) Auxiliary engines while such engines are operating primarily on liquefied natural gas or compressed natural gas.

(c) *Definitions.*

For purposes of this section, the definitions in Health and Safety Code sections 39010 through 39060 shall apply except as otherwise specified in this section:

(1) "Alternative Control Technologies" means technologies, techniques, or measures that reduce the emissions of NOx and PM from an auxiliary diesel engine other than shutting down the engine.

(2) "Auxiliary Engine" means an engine on an ocean-going vessel designed primarily to provide power for uses other than propulsion, except that all diesel-electric engines shall be considered "auxiliary diesel engines" for purposes of this section.

(3) "Baseline Fleet Emissions" means the total emissions from all vessels in a fleet during all berthing times in a calendar year or other specified time period. For purposes of calculating the baseline fleet emissions, the auxiliary engines on the vessels in the fleet shall be assumed to use marine diesel fuel while at berth.

(4) "Berthing Time" means the time period that begins when the vessel is first tied to the berth and ends when the vessel is untied from the berth.

(5) "California Ports" means:

(A) The Port of Hueneme, the Port of Los Angeles (POLA) and Port of Long Beach (POLB), the Port of Oakland, the Port of San Diego, and the Port of San Francisco;

(B) For purposes of this section, POLA and POLB are treated as one port.

(6) "Container Vessel" means a self-propelled ocean-going vessel constructed or adapted primarily to carry uniform-sized ocean freight containers.

(7) "Diesel Engine" means an internal combustion, compression-ignition (CI) engine with operating characteristics significantly similar to the theoretical diesel combustion cycle. The regulation of power by controlling fuel supply in lieu of a throttle is indicative of a compression ignition engine.

(8) "Diesel-Electric Engine" means a diesel engine connected to a generator that is used as a source of electricity for propulsion or other uses.

(9) "Diesel Particulate Matter" means the particles found in the exhaust of diesel engines, which may agglomerate and adsorb other species to form structures of complex physical and chemical properties.

(10) "Distributed Generation" shall have the same meaning as that term is defined in title 17, CCR, section 94202.

(11) "Docked at the Berth" means the state of being tied to a berth.

(12) "Emergency Event" means the period of time during which any of the following events occurs; the emergency event begins when such an event begins and ends when the event is over:

(A) Any situation arising from a sudden and reasonably unforeseen event beyond the control of the master that threatens the safety of the vessel;

(B) The utility serving the port states that electrical power will be temporarily unavailable as a result of equipment failure; or

(C) The electrical system at the terminal cannot provide electrical power as a result of equipment failure; or

(13) "Executive Officer" means the executive officer of the Air Resources Board (ARB), or his or her designee.

(14) "Fleet" means all container, passenger, and refrigerated cargo (reefer) vessels, visiting a specific California port, which are owned or operated under the direct control of the same person. Direct control includes, but is not limited to, vessels that are operated under a contract, lease, or other arrangement with a third-party for the third-party to operate the vessel. For the purposes of this section, a person shall be deemed to have separate fleets for each California port visited. For example, if a person owns or operates vessels that visit both the Port of Los Angeles and Port of Oakland, that person is deemed to have two fleets, one a "POLA-based fleet" and the other a "Port of Oakland-based fleet."

(15) "IMO" means the International Maritime Organization.

(16) "Landlord Port" means a California port that leases the port's real property to a person(s).

(17) "Master" means the person who operates an ocean-going vessel or is otherwise in charge of the vessel's operations.

(18) "Ocean-Going Vessel" means a commercial, government, or military vessel meeting any one of the following criteria:

(A) A vessel greater than or equal to 400 feet in length overall (LOA) as defined in 50 CFR § 679.2, as adopted June 19, 1996;

(B) A vessel greater than or equal to 10,000 gross tons (GT ITC) pursuant to the convention measurement (international system) as defined in 46 CFR § 69.51-.61, as adopted September 12, 1989; or

(C) A vessel propelled by a marine compression ignition engine with a per-cylinder displacement of greater than or equal to 30 liters.

For the purposes of this section, "ocean-going vessel" will be used interchangeably with the term "vessel."

(19) "Operate" means steering or otherwise running the vessel or its functions while the vessel is underway, moored, anchored, or at berth.

(20) "Operate an Auxiliary Diesel Engine" means running or idling an auxiliary diesel engine such that it is producing mechanical work or electricity or is otherwise consuming fuel.

(21) "Own" means having all the incidents of ownership, including the legal title, of a vessel whether or not that person leads, rents, or pledges the vessel; having or being entitled to the possession of a vessel as the purchaser under a conditional sale contract; or being the mortgagor of a vessel.

(22) "Oxides of Nitrogen" means compounds of nitric oxide (NO), nitrogen dioxide (NO_2), and other oxides of nitrogen, which are typically created during combustion processes and are major contributors to smog formation and acid deposition.

(23) "Particulate Matter" means any airborne finely divided material, except uncombined water, which exists as a liquid or solid at standard conditions (e.g., dust, smoke, mist, fumes, or smog).

(24) "Passenger Vessel" means a self-propelled vessel constructed or adapted primarily to carry people.

(25) "Person" includes all of the following:

(A) Any person, firm, association, organization, partnership, business trust, corporation, limited liability company, or company;

(B) Any state or local governmental agency or public district, or any officer or employee thereof;

(C) The United States or its agencies, to the extent authorized by federal law.

(26) "Post-Baseline Fleet Emissions" means the total emissions from all vessels in a fleet after the application of alternative control technologies during all berthing times in a calendar year or other specified time period. For purposes of calculating the baseline fleet emissions, the auxiliary engines on the vessels in the fleet shall be assumed to use marine diesel fuel while at berth.

(27) "Refrigerated Cargo (or Reefer) Vessel" means a self-propelled vessel constructed or adapted primarily to carry refrigerated cargo. Reefer vessels include vessels where the cargo may be stored in large refrigerated rooms within the vessel or vessels that carry exclusively refrigerated cargo containers.

(28) "Responsible Official" means the individual(s) with the authority to certify that all vessels in a fleet comply with applicable requirements of this regulation.

(29) "Shore power" refers to electrical power being provided by either the local utility or by distributed generation.

(30) "Steamship" means a self-propelled vessel in which the primary propulsion and electrical power are provided by steam boilers.

(31) "Synchronous Power Transfer" means the synchronized switchover in vessel-based power to shore-based power without a loss in power during such transfer.

(32) "Terminal" means a facility consisting of wharves, piers, docks and other berthing locations and adjacent storage, which are used primarily for loading and unloading of cargo or material from vessels or the temporary storage of this cargo or material on-site.

(33) "Terminal Operator" means a person that leases terminal property from a port for the purpose of loading and unloading of cargo or material from vessels or the temporary storage of this cargo or material on-site.

(34) "Utility" shall have the same meaning and be used interchangeably with the term "Electric Utility" as defined in Public Resources Code section 28105.

(35) "Verified Emission Control Strategy" means an emission control strategy that has been verified pursuant to the "Verification Procedure

for In-Use Strategies to Control Emissions from Diesel Engines" in title 13, California Code of Regulations, commencing with section 2700, which is incorporated herein by reference.

(36) "Visit" means the time period that begins when an ocean-going vessel initially ties to a berth (the beginning of the visit) and ends when it casts off the lines (the end of the visit) at a berth in a California port. Separate and sequential visits shall collectively be deemed a single visit when a vessel ties to two or more berths at the same California port and the time interval between leaving one berth and tying to another berth in the same port is less than two hours.

(d) Vessel In-Use Operational Requirements.

(1) Limits on Hours and Other Aspects of Operation for Auxiliary Diesel Engines on Container, Passenger, and Refrigerated Cargo (Reefer) Vessels.

(A) Except as provided in subsection (d)(2), beginning January 1, 2014, no less than 50 percent of a fleet's visits to a California port in a calendar quarter, rounded to the nearest whole visit, shall meet the following limits on the number of hours auxiliary diesel engines on such vessels may be operated at berth:

1. Three hours total per visit, provided the visiting vessel uses a synchronous power transfer process to change from vessel-based power to shore-based power; or

2. Five hours total per visit, provided the visiting vessel does not use a synchronous power transfer process to change from vessel-based power to shore-based power.

For example, if a person's fleet makes 10 visits to a California port in a calendar quarter, the auxiliary diesel engines on vessels in at least 5 of those visits shall be operated no more than a combined 3 or 5 hours total, depending on whether a synchronous power transfer is used. The 3- and 5-hour limit applies to the combined operating time for all auxiliary diesel engines used in a vessel visit, rather than on a per-engine basis.

(B) Except as provided in subsection (d)(2), beginning January 1, 2020, no less than 80 percent of a fleet's visits to a California port in a calendar quarter, rounded to the nearest whole visit, shall meet the following limits on the number of hours auxiliary diesel engines on such vessels may be operated at berth:

1. Three hours total per visit, provided the visiting vessel uses a synchronous power transfer process to change from vessel-based power to shore-based power; or

2. Five hours total per visit, provided the visiting vessel does not use a synchronous power transfer process to change from vessel-based power to shore-based power.

For example, if a person's fleet makes 10 visits to a California port in a calendar quarter, the auxiliary diesel engines on vessels in at least 5 of those visits shall be operated no more than a combined 3 or 5 hours total, depending on whether a synchronous power transfer is used. The 3- and 5-hour limit applies to the combined operating time for all auxiliary diesel engines used in a vessel visit, rather than on a per-engine basis.

(C) Compliance with the requirements in subsection (d)(1)(A) and (d)(1)(B) shall be determined quarterly for the periods specified as follows:

1. January 1 through March 31, inclusive;

2. April 1 through June 30, inclusive;

3. July 1 through September 30, inclusive; and

4. October 1 through December 31, inclusive.

(D) Except as otherwise specified in subsection (d)(1)(F), the requirements of subsection (d)(1)(A) and (d)(1)(B) do not apply to:

1. A fleet comprised solely of container or reefer vesselsthat visits a California port fewer than 25 times total in a calendar year; and

2. A fleet comprised solely of passenger vessels that visits a California port fewer than 5 times total in a calendar year.

(E) No person shall sell, supply, offer to supply, or purchase electrical power for use on a vessel during a visit in lieu of using the on-board auxiliary diesel engines, unless such electrical power is either supplied by the local utility or is otherwise generated by equipment that meet the following emission standards:

1. NOx emissions no greater than 0.03 gram per kilowatt-hour (g/kW-hr);

2. PM emissions equivalent to the combustion of natural gas with a fuel sulfur content of no more than one grain per 100 standard cubic foot;

3. CO_2 emissions shall be no greater than 500 g/kW-hr; and

4. Ammonia emissions no greater than five parts per million on a dry volume basis (ppmdv), if selective catalytic reduction is used.

(F) Notwithstanding the requirements specified in subsection (d)(1)(A) and (d)(1)(B), any ocean-going vessel equipped to receive shore power that visits a berth equipped to provide compatible shore power shall utilize the shore power during every visit to that berth. This requirement shall not apply under the following circumstances:

1. The master of the vessel reasonably and actually determines that an emergency event, as defined in subsection (c)(12)(A), is in effect and the use of shore power during the emergency event would endanger the vessel's safety. Shore power shall be used for the remainder of the visit once the master determines that the emergency event no longer exists;

2. An emergency event, as defined in subsection (c)(12)(B) or (c)(12)(C), is in effect. Shore power shall be used for the remainder of the visit once the emergency event is no longer in effect; or

3. The California Independent System Operator (CAISO) has declared a Stage 3 emergency and the utility providing electrical power to the port is requesting the terminal where the vessel is located to reduce the use of grid-based electrical power. Shore power shall be used for the remainder of the visit once CAISO declares the Stage 3 emergency is over.

(2) Emissions Reduction Option.

The purpose of this provision is to allow any person the option of complying with the requirements of this subsection (d)(2) in lieu of meeting the requirements of subsection (d)(1).

Requirements.

(A) For fleets visiting terminals that are providing electrical power from the utility's electrical grid, the owner or operator of the fleets shall comply with the following schedule:

1. For the quarter beginning on January 1, 2014, and each subsequent quarter through December 31, 2019, inclusive, the NOx and PM emissions at berth from the fleet's auxiliary engines must be reduced by 50 percent from the baseline fleet emissions.

2. For the quarter beginning on January 1, 2020, and each subsequent quarter thereafter, the NOx and PM emissions at berth from the fleet's auxiliary engines must be reduced by 80 percent from the baseline fleet emissions.

(B) For fleets visiting terminals that are providing electrical power from sources that are not part of an utility's electrical grid, or alternative control technologies are used to reduce the emissions of the fleet, the owner or operator of the fleet shall comply with the following schedule:

1. For the quarter beginning on January 1, 2010, and each subsequent quarter through December 31, 2011, inclusive, the NOx and PM emissions at berth from the fleet's auxiliary engines must be reduced by 20 percent from the baseline fleet emissions.

2. For the quarter beginning on January 1, 2012, and each subsequent quarter through December 31, 2013, inclusive, the NOx and PM emissions at berth from the fleet's auxiliary engines must be reduced by 40 percent from the baseline fleet emissions.

3. For the quarter beginning on January 1, 2014, and each subsequent quarter through December 31, 2015, inclusive, the NOx and PM emissions at berth from the fleet's auxiliary engines must be reduced by 60 percent from the baseline fleet emissions.

4. For the quarter beginning on January 1, 2016, and each subsequent quarter thereafter, the NOx and PM emissions from the fleet's auxiliary engines must be reduced by 80 percent from the baseline fleet emissions.

(C) For fleets visiting terminals that are using a combination of electrical power from the utility grid and electrical power from sources that are not part of an utility's electrical grid, or alternative control technologies, the following schedule applies:

1. For the quarter beginning on January 1, 2012, and each subsequent quarter through December 31, 2013, inclusive, the NOx and PM emissions at berth from the fleet's auxiliary engines must be reduced by 20 percent from the baseline fleet emissions.

2. For the quarter beginning on January 1, 2014, and each subsequent quarter through December 31, 2019, inclusive, the NOx and PM emissions from the fleet's auxiliary engines must be reduced by 50 percent from the baseline fleet emissions.

3. For the quarter beginning on January 1, 2020, and each subsequent quarter thereafter, the NOx and PM emissions from the fleet's auxiliary engines must be reduced by 80 percent from the baseline fleet emissions.

(D) Compliance with the requirements of subsection (d)(2)(A), (d)(2)(B), and (d)(2)(C) shall be determined quarterly for the periods specified as follows:

1. January 1 through March 31, inclusive;

2. April 1 through June 30, inclusive;

3. July 1 through September 30, inclusive; and

4. October 1 through December 31, inclusive.

(E) No person shall sell, supply, offer to supply, or purchase electrical power for use on a vessel during a visit in lieu of using the on-board auxiliary diesel engines, unless such electrical power is either be supplied by the local utility or is otherwise generated by equipment that meet the following emission:

1. NOx Emissions.

a. Up to and including December 31, 2013, the NOx emissions shall be no greater than 2 g/kW-hr at any time; and

b. Beginning January 1, 2014, the NOx emissions shall be no greater than 0.2 g/kW-hr at any time;

2. PM emissions shall be no greater than the PM emissions from combustion of natural gas with a fuel sulfur content of no more than one grain per 100 standard cubic foot;

3. CO_2 emissions shall be no greater than 500 g/kW-hr; and

4. Ammonia emissions shall be no greater than five ppmdv if selective catalytic reduction is used.

(e) Exemptions to the Three-Hour or Five-Hour Limited Auxiliary Engine Operation Requirement in Subsection (d)(1)(A)(1), (d)(1)(A)(2), (d)(1)(B)(1) and (d)(1)(B)(2).

(1) Emergency Event.

All of the following requirements apply to claimed exemptions based on emergency events:

(A) If the master of the vessel reasonably and actually determines that an emergency event, as defined subsection (c)(12), occurs during the vessel's visit to a California port, the master of the vessel may operate the vessel's auxiliary engines during the emergency event;

(B) The master shall not operate the vessel's auxiliary engines for more than one hour beyond the time when the master receives notification that the emergency event is over, determines that the emergency event is over, or should have known the emergency event is over; and

(C) The provisions of paragraph (B) above notwithstanding, the master may continue to operate the auxiliary engines for no more than five hours if the master receives notification that the emergency event is over, determines that the emergency event is over, or should have known the emergency event is over and the vessel is scheduled to leave port within five hours.

(2) Delays Caused By U.S. Coast Guard or Department of Homeland Security Inspections.

The Executive Officer may extend the three-hour/five-hour operational requirement in subsection (d)(1)(A) and (d)(1)(B) if the following criteria are met:

(A) The initial inspection and clearance of the vessel by the Department of Homeland Security exceeds one hour. The time extension granted shall be commensurate with the excess time necessary for inspection and clearance; or

(B) After the auxiliary engines have been put back into service pending departure from the berth, the scheduled departure of the vessel has been delayed by the United States (U.S.) Coast Guard or the Department of Homeland Security.

(f) Calculations for Emissions Reduction Option in Subsection (d)(2).

(1) For the purposes of subsection (d)(2)(A), (d)(2)(B), and (d)(2)(C), the percent emission reduction shall be calculated as follows:

Percent Reduction = (BFE – PBFE) / BFE

Where,

The baseline fleet and post-baseline fleet emissions are calculated as follows:

(A) Baseline Fleet Emissions (BFE).

The baseline fleet emissions of NOx and PM shall be calculated using the following formula:

Baseline Fleet Emissions = $\sum$ (emission rate x average berthing time x power requirement x visits)

Where:

"Emission rate" for each auxiliary engine is determined pursuant to subsection (f)(2);
"Average berthing time" for each vessel is determined for the applicable period specified in subsection (d)(2)(D);

"Power requirements" means the electrical power requirement for each vessel as determined pursuant to subsection (f)(3);

"Visits" means the total number of visits by the vessel during the applicable period specified in subsection (d)(2)(D); and

"Σ" means the summation over the entire fleet subject to the emission reduction option.

(B) Post-Baseline Fleet Emissions (PBFE).

The post-baseline fleet emissions of NOx and PM shall be calculated using the following formula:

Post-Baseline Fleet Emissions = Σ (emission rate x average berthing time x power requirement x visits x control factor)

Where:

"Emission rate" for each auxiliary engine is determined pursuant to subsection (f)(2);

"Average berthing time" for each vessel is determined for the applicable period specified in subsection (d)(2)(D);

"Power requirements" means the electrical power requirement for each vessel as determined pursuant to subsection (f)(3);

"Visits" means the total number of visits by the vessel during the applicable period specified in subsection (d)(2)(D);

"Control factor" means the applicable control factor specified in subsection (f)(4); and

"Σ" means the summation over the entire fleet subject to the emission reduction option.

(2) A person complying with the requirements of subsection (d)(2) may choose any of the following emissions rates for use in the calculations specified in subsection (f)(1)(A) and (f)(1)(B):

(A) Results from emission measurements for similar auxiliary diesel engines that are used to satisfy a marine engine standard, including U.S. Environmental Protection Agency (EPA) emission standards for marine engines (40 CFR Part 94), and the International Convention for the Prevention of Pollution from

Ships, 1973, as modified by the Protocol of 1978 (MARPOL 73/78), both of which are incorporated herein by reference;

(B) Emission measurements approved by the Executive Officer and using the test methods specified in subsection (f)(4)(B)(3); or

(C) In lieu of test data measured pursuant to paragraph (A) or (B) above, the following emission rates may be used as default values:

1. 13.9 g/kW-hr for NOx.

2. 0.38 g/kW-hr for PM if 0.11 to 0.5 percent sulfur marine gas oil is used as a fuel.

3. 0.25 g/kW-hr for PM if 0.10 or less sulfur content marine gas oil is used as a fuel.

(3) Power Requirements.

(A) The following values in Table 1 may be used as default values for power requirements:

Table 1.

Ship Category	Ship Size / Type	Default Power Requirement (kW)
Container Vessel	<1000 TEU	1,000
	1,000-1,999 TEU	1,300
	2,000-2,999 TEU	1,600
	3,000-3,999 TEU	1,900
	4,000-4,999 TEU	2,200
	5,000-5,999 TEU	2,300
	6,000-6,999 TEU	2,500
	7,000-7,999 TEU	2,900
	8,000-9,999 TEU	3,300
	10,000-12,000 TEU	3,700
Passenger Vessel		No Default Value – Use Actual Load
Reefer	Break Bulk	1,300
	Fully Containerized	3,300

TEU = twenty-foot equivalent unit.
kW = kilowatt

(B) In lieu of the default values above, the fleet operator may, with adequate supporting documentation, use the following:

1. The actual shore power usage, on a monthly basis, rounded to the nearest whole kW-hrs, of the vessels in the fleet utilizing shore power, or

2. The actual on-board power usage, on a monthly basis, rounded to the nearest whole kW-hrs, of the vessels in the fleet utilizing alternative control technologies.

(4) Control Factors.

(A) The emissions from vessels using grid power in lieu of the vessel's auxiliary engines when the vessels are at berth are presumed to be reduced by 90 percent.

(B) No control efficiencies for alternative control technologies shall be used to comply with the requirements of this provision unless the control efficiencies are calculated or measured as follows:

1. The control efficiencies shall be based on an emission test protocol that is approved by the Executive Officer prior to conducting the emission measurements;

2. The results of the emission measurements conducted pursuant to paragraph 1 above are approved by the Executive Officer; and

3. Emission measurements are conducted using the following test methods:

a. NOx and CO_2 shall be measured using California Air Resources Board (CARB) Test Method 100, dated July 1997, which is incorporated herein by reference, or equivalent district-approved test method;

b. Diesel PM shall be measured using ISO 8178 Test Procedures: ISO 8178-1: 1996(E) ("ISO 8178 Part 1"); ISO 8178-2:1996(E) ("ISO 8178 Part 2"); and ISO 8178-4: 1996(E) ("ISO 8178 Part 4"), all of which are incorporated herein by reference; and

c. Ammonia slip shall be measured using the Bay Area Air Quality Management District Source Test Procedure ST-1B, Ammonia Integrated Sampling, dated

January 1982, which is incorporated herein by reference, or other equivalent district approved test method.

d. The sulfur content of fuels shall be determined pursuant to International Standard ISO 8754 (as adopted in 2003), which is incorporated herein by reference.

(C) Results from emission measurements from a verified emission control strategy may be used in conjunction with engine emission information.

(D) The Executive Officer may request periodic emission testing or other types of monitoring to verify the proper operation of alternative control technologies or to verify the emission rate of an auxiliary engine.

1. At a minimum, emission control technologies shall be tested as follows and the results of such testing provided to the Executive Officer within 30 days of the testing:

a. Shore-based systems shall be tested annually to demonstrate the overall percentage of emission reduction being achieved.

b. Catalyst based air pollution control systems installed on vessels shall be tested after every 1,000 hours of operation to determine the overall percentage of emission reduction being achieved.

c. If Selective Catalytic Reduction (SCR) is used as a control technology, the emissions of ammonia shall also be measured at the same time the NOx emissions are being measured.

2. The Executive Officer may modify the testing frequency as he/she deems appropriate.

(g) *Terminal Plan Requirements.*

(1) A terminal that receives more than 50 vessel visits in 2008 shall submit a plan for the Executive Officer's approval that discusses how the terminal will accommodate the vessels that will visit the terminal who are subject to subsection (d)(1) and (d)(2). The terminal shall submit the plan and subsequent updates to the plan according to the schedule below (Table 2). The plan updates shall address any contingencies

that may be necessary for the vessels to meet the requirements of subsection (d)(1)and (d)(2) by the applicable dates.

Table 2.

Vessel Compliance Option	Initial Terminal Plan Due Date	Subsequent Terminal Plan Updates
Grid-Based Shore Power: (d)(1) and (d)(2)(A)	July 1, 2009	July 1, 2013 July 1, 2019
Alternative Control Technologies to Grid-Based Shore Power: (d)(2)(B)	July 1, 2009	July 1, 2011 July 1, 2013 July 1, 2015
Combination of Grid-Based Shore Power and Alternative Control Technologies: (d)(2)(C)	July 1, 2009	July 1, 2011 July 1, 2013 July 1, 2015 July 1, 2019

(2) Plan Requirements for Grid-Based Shore Power.

(A) Specify the schedule for implementing infrastructure modifications, including the following:

1. Utility infrastructure improvements, if any, outside the port boundary;

2. Improvements to port infrastructure; and

3. Major infrastructure improvements to terminal.

(B) Identification of existing berths to be modified or new berths to be constructed that will satisfy the requirements of subsection (d)(1).

(3) Plan Requirements for Alternative Control Technologies.

(A) Description of the approach that will be used to reduce in-berth vessel emissions, including whether the approach is a vessel-based approach or shore-based approach;

(B) Identification and description of equipment;

(C) Berth(s) where the equipment will be used;

(D) Specific vessels affected by the technology; and

(E) Estimate of the expected reductions in NOx and PM emissions from vessels using the technology, including documentation supporting the anticipated reductions.

(4) Plan Requirements for a Combination of Grid-Based Shore Power and Alternative Control Technologies.

(A) Identification of which berths will implement grid-based shore power and which berths will implement alternative control technologies

(B) For berths implementing shore-based grid power, the plan must contain the information specified in subsection (g)(2).

(C) For berths implementing alternative control technologies, the plan shall contain the information specified in subsection (g)(3).

(5) A port may submit terminal plans required under subsection (g)(1) on behalf of the terminals located at that port.

(h) *Reporting and Recordkeeping Requirements.*

(1) Reporting and Recordkeeping Requirements for Persons that Comply with Subsection (d)(1).

(A) The Responsible Official shall provide the following reports to the Executive Officer:

1. A vessel fleet plan, due to the Executive Officer by July 1, 2013, and an updated plan by July 1, 2019, which includes a listing of the vessels that would be affected by the requirements specified in subsection (d)(1) and the description of the ability of each vessel to use shore power.

The vessel fleet plan shall list the vessels that are able to shut down the vessel's auxiliary engines and use shore power, along with the related information as follows:

a. Name of the vessel, Lloyd's number for the vessel, and vessel category (container, passenger, or reefer); and

b. The port(s) each vessel(s) is expected to visit.

2. An annual statement of compliance pursuant to subsection (d)(1) and (d)(2).

   a. The initial annual statement of compliance is due to the Executive Officer by March 1, 2015. This statement is for the 2014 calendar year. Thereafter, the annual statement is due to the Executive Officer by March 1 of each year, certifying compliance with the requirements for the previous calendar year.

   b. The annual statement of compliance shall include the following:

      i. A statement signed by the Responsible Official that the requirements specified in subsection (d)(1) or (d)(2) have been met.

      ii. Visit-related information for all vessels within a fleet that visited a California port. The list shall include the following information for each vessel:

         I. Current name of the vessel;
         II. Lloyd's number for the vessel;
         III. Vessel type (cargo, passenger, reefer); and
         IV. Visits, by port and terminal, where the auxiliary engines were shut down;

      iii. The information submitted pursuant to paragraph 2.b.ii above shall be reported for the following

i. When the vessel initially tied to the berth and when the vessel cast-off the tie lines;

ii. When the Department of Homeland Security released the vessel;

iii. When the auxiliary engines were initially shut down and subsequently restarted;

iv. Whether departure from the berth was delayed by the U.S. Coast Guard or other federal agency and identification of the agency that caused the delay;

v. If an emergency event occurred, a description of that emergency event;

vi. If the vessel could not use shore power as a result of the CAISO declaring a stage 3 emergency, and

vii. If a vessel could not use shore power as a result of equipment failure aboard the vessel.

b. Copies of all current U.S. Department of Homeland Security Bureau of Customs and Border Protection "Vessel Entrance or Clearance Statement" documents (CBP Form 1300, version 02/02), which is incorporated herein by reference, if the vessel operator or owner is claiming an exemption pursuant to subsection (e)(2)(A) or (e)(2)(B).

2. All records required pursuant to this provision shall be retained for a minimum of five years.

(2) Reporting and Recordkeeping Requirements for Persons Opting to Comply with the Emissions Reduction Option in Subsection (d)(2).

(A) The Responsible Official shall provide the following reports to the Executive Officer:

1. A vessel fleet plan, due to the Executive Officer by the dates shown in Table 3 below:

Table 3.

Compliance Option	Initial Vessel Fleet Plan	Subsequent Submittal Due Dates
Grid-Based Shore Power: (d)(2)(A)	July 1, 2013	July 1, 2019
Alternative Control Technologies to Grid-Based Shore Power: (d)(2)(B)	July 1, 2009	July 1, 2011 July 1, 2013 July 1, 2015
Combination of Grid-Based Shore Power and Alternative Control Technologies: (d)(2)(C)	July 1, 2011	July 1, 2013 July 1, 2019

The vessel fleet plan shall include the following items:

a. List of the vessels included in the company's fleet; Lloyd's number for each vessel, vessel category (cargo, passenger, reefer), average number of reefer containers carried by the vessel over the calendar year (container vessels only), and power requirement for each vessel (passenger and reefer vessels); and

b. Identify the potential alternative control techniques that may be used to achieve the requirements specified in subsection (d)(2). For each control technique, specify the following:

i. The vessels that would be affected by the technique;

ii. The status of implementation of the alternative control technique; and

iii. The basis used in determining the expected emission reduction, including submittal of any emission testing or other documentation.

2. An annual statement of compliance.

a. The initial annual statement of compliance is due to the Executive Officer by the dates in Table 4 below:

Table 4.

Compliance Option	Initial Submittal of Annual Statement of Compliance
Grid-Based Shore Power: (d)(2)(A)	March 1, 2015
Alternative Control Technologies to Grid-Based Shore Power: (d)(2)(B)	March 1, 2011
Combination of Grid-Based Shore Power and Alternative Control technologies: (d)(2)(C)	March 1, 2013

Thereafter, the annual compliance statement is due to the Executive Officer by March 1 of each year, certifying compliance with the requirements for the previous year.

b. The following items, applicable to the calendar year in question, should be included with the statement of compliance:

i. A statement signed by the Responsible Official indicating that the NOx and PM emission reductions specified by (d)(2) have been achieved;

ii. The calculated NOx and PM baseline and post-baseline emissions for each fleet, on a quarterly basis, as specified in (d)(2)(D). Include each vessel's contribution to the fleet's baseline and post-baseline emissions; and

iii. Description of the technique(s) used, including alternative controls technology (or technologies), achievable emission reductions, and supporting documentation (e.g., source test results or verification documentation). For subsequent statements of compliance, the supporting documents can be referenced.

(B) Recordkeeping.

1. The following records shall be kept at a central location by the master and the fleet vessel operator. This information

shall be supplied to the Executive Officer within 30 days of a request from ARB staff.

For each calendar year of vessel activity, a quarterly summary of emissions that demonstrates compliance with the applicable emission reduction (2010, 2012, 2014, or 2016), which includes the following:

a. The fleet's baseline and post-baseline levels for NOx and PM emissions; and

b. Each vessel's contribution to fleet's baseline and post-baseline NOx and PM emissions, including the following information:

   i. Name of each vessel;

   ii. Lloyd's number for each vessel;

   iii. Fuel type and average sulfur content of fuel for each vessel;

   iv. NOx and PM emissions for each vessel;

   v. Average hotelling time for each vessel;

   vi. Power requirements for each vessel while at berth;

   vii. For container vessels, the number of reefer containers imported and exported for each container vessel;

   viii. Total visits to each California port made by the vessel;

   ix. Technology used to reduce emissions and associated control factor used, and

   x. Any equipment failure aboard a vessel that prevented the vessel from using the emissions reduction technology

2. Records made pursuant to paragraph (2)(B) above shall be kept for a minimum of five years.

(3) Reporting and Recordkeeping Requirements for Ports and Terminals.

(A) Affected ports shall provide wharfinger information to the Executive Officer annually, beginning with the wharfinger information for calendar year 2010.

1. This information shall be provided to the Executive Officer no later than April 1 of the following year.

2. At a minimum, the wharfinger information shall include for each vessel visiting the port:

a. Name of the vessel;

b. Vessel type;

c. Company operating the vessel;

d. Lloyd's number for each vessel;

e. Berth used by the vessel; and

f. Date(s) and time the vessel was initially tied to the berth and subsequently released from the berth.

(B) The terminal operator shall keep the following records. These records shall be supplied to the Executive Officer within 30 days of a request from ARB staff:

1. Electricity usage for shore power:

a. Monthly utility billing statements that separately identify electricity supplied for shore power;

b. Episodes of electrical service interruption by local utility company, as confirmed and documented by local utility company; and

c. For distributed generation, monthly records that contain the following:

i. Names of vessels serviced;
ii. Location of vessels serviced, by berth;
iii. Date and time of use; and
iv. Power, in megawatts, supplied to the vessels.

2. Date, time, and description of equipment failure that affected the ability of vessels to turn off their auxiliary engines or use alternative control technologies to reduce emissions pursuant to (d)(2).;

3. Record of each vessel that did not operate its auxiliary engines while the vessel was docked at the terminal:

   a. Name of vessel; and

   b. Date and time each vessel was initially tied to the terminal.

4. Records made pursuant to paragraph (3)(B) above shall be kept for five years.

(4) Electronic submittals of records and other information required under this section may be approved by the Executive Officer upon request, provided such electronic submittals use digital signatures that meet the requirements specified in Government Code section 16.5. Notwithstanding the approved submittal of electronic records, the Executive Officer may request the submittal of a hard copy of any electronic submittal.

(i) *Violations.*

(1) Except as otherwise specified in this subsection, any person who is subject to this section and commits a violation of any provision, prohibition, limit, standard, criteria, or requirement in this section is subject to the penalties, injunctive relief, and other remedies specified in Health and Safety Code section 42400 et seq., other applicable sections in the Health and Safety Code; and other applicable provisions as provided under California law for each violation. Nothing in this section shall be construed to limit or otherwise affect any applicable penalties or other remedies available under federal law.

(2) Except as otherwise specified in this subsection, any failure to meet any provision, prohibition, limit, standard, criteria, or requirement in this section, including but not limited to the applicable emission limits for supplied shore power and hours of engine operation limits, shall constitute a single, separate violation of this section for each hour that a person operates the auxiliary diesel engine until such provision, prohibition, limit, standard, criteria, or requirement has been met.

(3) A violation of the recordkeeping and reporting requirements in this section shall constitute a single, separate violation of this section for

each day that the applicable recordkeeping or reporting requirement has not been met.

(j) *Severability.*

If any subsection, paragraph, subparagraph, sentence, clause, phrase, or portion of this regulation is, for any reason, held invalid, unconstitutional, or unenforceable by any court of competent jurisdiction, such portion shall be deemed as a separate, distinct, and independent provision, and such holding shall not affect the validity of the remaining portions of the regulation.

NOTE: Authority cited: Sections 39600, 39601, 39650, 39658, 39659, 39666 and 41511, Health and Safety Code. Reference: Sections 39650, 39658, 39659, 39666, 41510, and 41511, Health and Safety Code.

CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC MEETING TO HEAR A REPORT ON STAFF'S NONATTAINMENT AREA RECOMMENDATIONS FOR THE REVISED FEDERAL PM2.5 STANDARD

The Air Resources Board (the Board or ARB) staff will present nonattainment area recommendations for the new federal 35 ug/m^3 24-hour $PM_{2.5}$ standard. ARB will submit these recommendations to the United States Environmental Protection Agency (U.S. EPA) by December 18, 2007.

DATE: December 6 & 7, 2007

TIME: 9:00 a.m.

PLACE: Air Resources Board
Auditorium
9530 Telstar Avenue
El Monte, California 91731

This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., December 6, and will continue at 8:30 a.m., December 7, 2007. This item is expected to be considered on December 7, 2007. Please consult the agenda for the meeting, which will be available at least 10 days before December 6, 2007, to determine the day on which this item will be considered.

For individuals with sensory disabilities, this document is available in Braille, large print, audiocassette or computer disk. Please contact ARB's Disability Coordinator at (916) 323-4916 by voice, or through the California Relay Services at 711, to place your request for disability services. If you are a person with limited English and would like to request interpreter services, please contact ARB's Bilingual Manager at (916) 323-7053.

BACKGROUND

The federal Clean Air Act requires U.S. EPA to set health-based National Ambient Air Quality Standards. On December 18, 2006, U.S. EPA lowered the 24-hour $PM_{2.5}$ standard from 65 ug/m^3 to 35 ug/m^3. Due to the standard revision, ARB is required to submit nonattainment area recommendations and appropriate boundaries to U.S. EPA for this standard by December 18, 2007. The nonattainment area recommendations are based on 2004-2006 $PM_{2.5}$ air quality monitoring data.

U.S. EPA plans to finalize nonattainment area designations effective April 2009, based on 2005-2007 $PM_{2.5}$ air quality monitoring data. State implementation plans will be due

three years after the effective date of designations. Attainment for this new standard will be required by April 2019.

PROPOSED ACTION

ARB staff will present the recommendations that will be provided to U.S. EPA regarding proposed $PM_{2.5}$ nonattainment areas for the new 35 ug/m^3 24-hour standard. Consistent with federal guidance, ARB staff reviewed 2004-2006 monitoring data and identified the areas that exceeded the standard. These areas are the South Coast Air Quality Management District, the San Joaquin Valley Air Pollution Control District, the Bay Area Air Quality Management District, the Sacramento Air Quality Management District, the combined cities of Yuba City/Marysville, the city of Chico, and the city of Calexico. No Board action is required.

AVAILABILITY OF DOCUMENTS

ARB staff will prepare a written Staff Report prior to the meeting. Copies of the Staff Report may be obtained from the Board's Public Information Office, 1001 "I" Street, 1st Floor, Environmental Services Center, Sacramento, California 95814, (916) 322-2990. This notice and Staff Report may also be obtained from ARB's internet site at www.arb.ca.gov/desig/pm25desig/pm25desig.htm.

SUBMITTAL OF COMMENTS

Interested members of the public may also present comments orally or in writing at the meeting, and in writing or by email before the meeting. To be considered by the Board, written comment submissions not physically submitted at the meeting must be received **no later than 12:00 noon, December 5, 2007,** and 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

Facsimile submittal: (916) 322-3928

Please note that under the California Public Records Act (Government Code section 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 30 copies of any written statement be submitted and that written and email statements be filed at least 10 days prior to the meeting so that ARB staff and Board members have time to fully consider each

comment. Further inquiries regarding this matter should be directed to Ms. Sylvia Zulawnick, Manager of the Particulate Matter Analysis Section, Planning and Technical Support Division, at (916) 324-7163, 1001 I Street, Sacramento, California 95814 or by email at szulawni@arb.ca.gov, or Jill Glass, Air Pollution Specialist, Planning and Technical Support Division at (916) 322-6161, 1001 I Street, Sacramento, California 95814 or by email at jglass@arb.ca.gov.

CALIFORNIA AIR RESOURCES BOARD

James N. Goldstene
Executive Officer

Date: November 20, 2007

TITLE 13. CALIFORNIA AIR RESOURCES BOARD

NOTICE OF PUBLIC HEARING TO CONSIDER THE ADOPTION OF PROPOSED REGULATION TO CONTROL EMISSIONS FROM IN-USE ON-ROAD DIESEL-FUELED HEAVY-DUTY DRAYAGE TRUCKS AT PORTS AND INTERMODAL RAIL YARD FACILITIES

The Air Resources Board (the Board or ARB) will conduct a public hearing at the time and place noted below to consider adoption of a regulation to reduce emissions of diesel particulate matter (PM) and oxides of nitrogen (NOx) from drayage trucks that operate at ports and intermodal rail yards in California. Motor carriers that dispatch drayage trucks, port terminals and rail yards, port and rail authorities, drayage truck drivers, and drayage truck owners would be subject to and have responsibilities under this regulation. This notice summarizes the proposed regulation. The Staff Report: Initial Statement of Reasons (Staff Report) and Technical Support Document present the regulation and information supporting the adoption of the regulation in greater detail.

DATE: December 6, 2007

TIME: 9:00 a.m.

PLACE: Air Resources Board
Auditorium
9530 Telstar Avenue
El Monte, California 91731

This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., December 6, 2007, and may continue at 8:30 a.m., December 7, 2007. This item may not be considered until December 7, 2007. Please consult the agenda for the meeting, which will be available at least 10 days before December 6, 2007, to determine the day on which this item will be considered.

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INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Section Affected: Proposed adoption of new section 2027, title 13, California Code of Regulations (CCR).

Background

Over 90 percent of Californians breathe unhealthful air at times. To improve air quality and human health, ARB establishes requirements to reduce emissions from new and in-use on-road and off-road vehicles, engines, and other sources. Over the past 30 years, as part of ARB's mission to address air pollution in the state, the Board has adopted a series of regulations requiring manufacturers of new motor vehicles and engines to meet ever more stringent emission standards.[1] Along with the U.S. Environmental Protection Agency (U.S. EPA), ARB has most recently adopted new emission standards for 2007 model year heavy-duty engines[2] that reduce particulate matter (PM) emissions by 90 percent compared to pre-2007 emission standard engines and emission standards for 2010 model year heavy-duty engines that reduce oxides of nitrogen (NOx) emissions by 90 percent compared to pre-2007 emission standard engines.[3] However, at the ports and intermodal rail yard facilities, drayage trucks are typically not new, but are older and more polluting. Some of the trucks in operation at these locations are more than 20 years old. Because of the slow turnover in these vehicles and the high risk associated with diesel PM emissions, ARB staff is proposing that emissions from in-use drayage trucks that operate at California's ports and intermodal rail yards be reduced.

Control of Toxic Air Contaminants and Criteria Pollutants

The California Toxic Air Contaminant Identification and Control Program (Air Toxics Program), established under California law by Assembly Bill 1807 (Stats. 1983, ch. 1047) and set forth in Health and Safety Code (HSC) sections 39650 through 39675, requires ARB to identify and control air toxic air contaminants (TACs) in California. The identification phase of the Air Toxics Program requires ARB, with participation of other state agencies, such as the Office of Environmental Health Hazard Assessment, to evaluate the health impacts of and exposure to substances, and to identify those substances that pose the greatest health threat as toxic air contaminants. The ARB's evaluation is made available to the public and is formally reviewed by the Scientific Review Panel (SRP) established under HSC section 39670. Following ARB's evaluation and the SRP's review, the Board, pursuant to section 39662, may formally identify a TAC at a public hearing. Following identification, HSC sections 39658, 39665, and 39666 require ARB, with participation of the air pollution control and air quality management districts (districts), and in consultation with affected sources and interested parties, to prepare a report on the need and appropriate degree of regulation

[1] Title 13, California Code of Regulations (CCR), chapter 1, article 2, sections 1950 et seq.
[2] Engines equipped on heavy-duty vehicles having a gross vehicle weight rating over 14000 pounds
[3] Title 13, CCR, section 1956.8.

for that substance (a "needs assessment") and to adopt airborne toxic control measures (ATCMs) for nonvehicular sources. Based on its determination under section 39662 and pursuant to HSC section 39667, ARB is responsible for considering and adopting emission standards and other ATCMs for vehicular sources to achieve the maximum possible reductions in public exposure to TACs.

In 1998, the Board identified diesel PM as a TAC with no Board-specified threshold exposure level. A needs assessment for diesel PM was conducted between 1998 and 2000, which resulted in ARB staff developing and the Board approving a Risk Reduction Plan to Reduce Particulate Matter Emissions from Diesel-Fueled Engines and Vehicles (Diesel RRP) in 2000. The Diesel RRP presented information that identified the available options for reducing diesel PM and recommended control measures to achieve further reductions. The scope of the Diesel RRP was broad, addressing all categories of engines, both mobile and stationary, including those covered by the proposed regulation. The ultimate goal of the Diesel RRP is to reduce California's diesel PM emissions and associated cancer risks from 2000 baseline levels by 85 percent by 2020.

HSC sections 43013, and 43018 further direct ARB to adopt standards and regulations that the Board has found to be necessary, cost-effective, and technologically feasible to achieve emission reductions of identified criteria pollutants that affect the State's health and welfare from various new and in-use mobile source categories.

The purpose of this proposed regulatory action is to reduce emissions of diesel PM and NOx. Diesel PM emission reductions are needed to reduce the potential cancer risk and other adverse effects from PM exposure to people who live in the vicinity of California's ports, intermodal rail yards, and nearby roadways. Reductions in diesel PM and NOx (which forms "secondary" nitrate PM in the atmosphere) will also contribute to regional PM reductions that will assist in California's progress toward achieving State and federal air quality standards. Reductions in NOx, an ingredient in the formation of ozone pollution, will also help reduce regional ozone levels.

Diesel engines on drayage trucks are a significant source of diesel PM and NOx emissions in California. The proposed regulation would provide needed diesel PM emission reductions in 2010 and NOx reductions in 2014 throughout California after full regulatory implementation. These emission reductions would occur in areas near ports and intermodal rail yards, many of which are designated non-attainment for the State and federal ambient air quality standards for PM_{10}, $PM_{2.5}$ and ozone.

Attainment of Ambient Air Quality Standards

The federal Clean Air Act (CAA) requires U.S. EPA to establish National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health, including fine particulate matter ($PM_{2.5}$) and ozone. Set to protect public health, the NAAQS are adopted based on a review of health studies by experts and a public process. Ambient $PM_{2.5}$ is associated with premature mortality, aggravation of respiratory and

cardiovascular disease, asthma exacerbation, chronic and acute bronchitis and reductions in lung function. Ozone is a powerful oxidant. Exposure to ozone can result in reduced lung function, increased respiratory symptoms, increased airway hyper-reactivity, and increased airway inflammation. Exposure to ozone is also associated with premature death, hospitalization for cardiopulmonary causes, and emergency room visits for asthma.

Areas in the State that exceed the NAAQS are required by federal law to develop State Implementation Plans (SIPs) describing how they will attain the NAAQS by certain deadlines. The NOx emission reductions are needed because NOx leads to formation in the atmosphere of both ozone and $PM_{2.5}$; diesel PM emission reductions are needed because diesel PM contributes to ambient concentrations of $PM_{2.5}$.

The South Coast Air Quality Management District (SCAQMD) and the San Joaquin Valley Air Pollution Control District (SJVAPCD) are designated as nonattainment of both the federal 8-hour ozone and federal PM2.5 NAAQS. In order to demonstrate that the necessary emission control programs are in place, the U.S. EPA requires that all necessary emission reductions be achieved by 2014 for PM2.5 and 2023 for ozone.

In both the South Coast and San Joaquin Valley air basins, air quality modeling indicates that significant reductions of NOx are crucial to help meet the federal standards. For example, at this time, the strategy to achieve attainment of the $PM_{2.5}$ standards in the South Coast Air Basin includes staff estimates that a 55 percent reduction in NOx emissions from 2006 levels (i.e., a total reduction of hundreds of tons per day) and a 15 percent reduction in direct $PM_{2.5}$ emissions from 2006 baseline levels will be necessary for attainment of the $PM_{2.5}$ standards in the South Coast Air Basin. The NOx emission reductions from the proposed regulation would play an essential role in assisting the South Coast Air Basin with meeting its 2014 $PM_{2.5}$ deadline as well as its future ozone deadlines.

The federal CAA permits states to adopt more protective air quality standards if needed, and California has set standards for particulate matter and ozone that are more protective of public health than respective federal standards. The Bay Area, South Coast, San Joaquin Valley, and San Diego areas are nonattainment for the State standards for ozone and $PM_{2.5}$. HSC section 40911 requires the local air districts to submit plans to the Board for attaining the State ambient air quality standards, and HSC section 40924 requires triennial updates of those plans. The NOx and $PM_{2.5}$ emission reductions from the proposed regulation will assist the local air districts in achieving attainment of the State ambient air quality standards.

Control of Emissions from Goods Movement-Related Activities

In April 2006, the Board approved the *Emission Reduction Plan for the Ports and Goods Movement in California*. The plan identifies strategies for reducing emissions created from the movement of goods through California ports and into other regions of the State. The Emission Reduction Plan is part of the broader Goods Movement Action

Plan (GMAP) being jointly carried out by the California Environmental Protection Agency and the Business, Transportation, and Housing Agency. Phase I of the GMAP was released in September 2005 and highlighted the air pollution impacts of goods movement and the urgent need to mitigate localized health risk in affected communities. The final GMAP was released in January 2007 and includes a framework that identifies the key contributors to goods movement-related emissions.

The Emission Reduction Plan identifies numerous strategies for reducing emissions from all significant emission sources involved in goods movement, including ocean-going vessels, harbor craft, cargo handling equipment, locomotives, and trucks. The Plan identifies several strategies for reducing emissions from drayage trucks. The Plan establishes emission reduction goals for drayage trucks including modernizing (replacing and/or retrofitting) port trucks, implementing CA/US 2007 truck emission standards, and restricting entry of trucks new to port service unless equipped with diesel PM controls. The proposed regulation would represent a significant first step toward satisfying the Emission Reduction Plan goals by requiring the replacement and/or retrofit of trucks to meet newer more stringent emissions requirements.

The California Global Warming Solutions Act of 2006

The California Global Warming Solutions Act of 2006 established requirements for the first-in-the-world comprehensive program of regulatory and market mechanisms to achieve real, quantifiable, cost-effective reductions of greenhouse gases (GHG).[4] The legislation gave ARB responsibility for monitoring and reducing GHG emissions. The statute requires ARB to adopt regulations and other requirements that would reduce by 2020 statewide GHG to the equivalent of 1990 levels.

Some actions required by the proposed regulation may result in slightly increased carbon dioxide (CO_2) for some applications. This may occur, for example, if truck owners choose to comply with the regulations by using exhaust treatment technologies that could potentially decrease a vehicle's fuel economy or increase the weight of the vehicle. However, other actions in the proposed regulation would likely offset this effect. For instance, the accelerated phase in of newer engines, which employ modern, less polluting technologies, should reduce GHG emissions from each new engine relative to the older, in-use engines. In addition, the proposed regulation would reduce emissions of black carbon (a component of diesel PM and a likely contributor to global warming), which would further offset the minor increases in CO_2 emissions that may occur in some applications. Thus, staff expects the proposed regulations to have an overall negligible effect on global warming.

[4] Established under California law by Assembly Bill 32 (Stats. 2006, ch. 488) and set forth in HSC § 38500 et seq. Greenhouse gases are those that tend to increase average global temperatures through absorption of infrared radiation or other mechanisms. These include, but are not limited to, carbon dioxide (CO2) and methane (CH4).

Authority

The ARB has authority under California law to adopt the proposed regulation. Health and Safety Code sections 39650 through 39675, 43013(b), 43018 and 43600 provide broad authority for ARB to adopt emission standards and other regulations to reduce toxic and criteria air pollutant emissions from new and in-use vehicular, nonvehicular and other mobile sources.

Emission Reductions and Public Health Benefits Projected

The proposed regulation is expected to significantly reduce emissions of diesel PM from drayage trucks operated at California ports and intermodal rail yard facilities. Diesel PM emission reductions are needed to reduce premature mortality, cancer risk, and other adverse impacts from exposure to this TAC. The proposal would help achieve the 2020 goal set forth in the 2000 Diesel RRP of reducing diesel PM by 85 percent from 2000 baseline levels and the 2020 goals of the GMREP of reducing diesel PM by 88 percent. The proposed regulation would also reduce NOx emissions that contribute to exceedances throughout the State of ambient air quality standards for both $PM_{2.5}$ and ozone. These reductions will assist California in its goal of achieving state and federal air quality standards. Additionally, these emission reductions would occur in areas along the ports, intermodal rail yards, and nearby roadways where environmental justice concerns are especially prevalent.

The diesel PM and NOx emission reductions from the proposal are expected to reduce the number of people exposed to an increased cancer risk surrounding California's ports and intermodal rail yards, and especially near the Los Angeles/Long Beach Ports. Statewide, the emission reductions would significantly reduce premature deaths and cases of asthma-related and other lower respiratory symptoms by the year 2020, as well as other health benefits.

In contrast to the diesel PM and NOx reductions, staff is not projecting significant reductions in oxides of sulfur (SOx) from the proposed action. Currently, all diesel fuel sold to on-road vehicles is required to meet ARB's on-road diesel specifications (CARB diesel). These specifications help reduce SOx emissions, among other pollutants.

Staff Report and Further Information

As described in more detail below, ARB staff has prepared two documents as part of this rulemaking, a Staff Report and a Technical Support Document. Together with the needs assessment (i.e., the Diesel RRP), these two documents serve as the report on the need and appropriate degree of regulation for drayage trucks operating at California's ports and intermodal rail yards.

Description of the Proposed Regulatory Action

Under the approach proposed by staff, the Board would adopt a regulation, pursuant to its authority under the HSC, which would apply to the emissions from diesel engines on

drayage trucks operating at any of California's ports and intermodal rail yards (as defined in the proposal).

Applicability

The proposed regulation applies to any person who owns or operates a diesel-fueled drayage truck that operates at California ports and/or intermodal rail yards within 80 miles of ports. In addition to owners and operators of drayage trucks that operate at ports and intermodal rail yard facilities, the proposed regulation would also establish requirements for port and rail authorities, port terminals operators, intermodal rail yards, motor carriers, and potentially other businesses located on port and rail yard property

Exemptions

The proposed regulation includes a number of exemptions. The proposal does not apply to dedicated trucks of uni-body design, emergency vehicles, military tactical or combat support vehicles, and yard trucks. Additionally, the proposed regulation would also grant the ARB Executive Officer the ability to authorize an emergency decree that allows non-compliant vehicles into the ports and rail yards in the event of natural emergencies. The proposed regulation would also give the ARB Executive Officer the ability to grant exemptions for ports, providing certain requirements are met (i.e. areas such as marine estuaries that have no truck traffic, and ports where the overwhelming amount of traffic comes from exempted drayage trucks).

Emission Limits for Drayage Trucks

The regulation would set requirements in two phases for drayage trucks that operate at California ports and intermodal rail yards located within 80 miles of ports. By December 31, 2009, Phase 1 of the emission limits would achieve substantial near-term PM reductions to reduce adverse health affects in nearby local communities. Phase 2 of the limits would achieve additional emission reductions by December 31 2013 that are necessary for the State to meet its SIP commitments in federal non-attainment areas.

In general, to continue to operate at ports and intermodal rail yards, drayage trucks would have to meet more stringent emission standards by December 31, 2009. By that date, all drayage trucks operating at the ports or intermodal rail yards would be required to either be equipped with a 1994-2003 model-year engine certified to California or federal emission standards and have a level 3 ARB verified emission control device strategy (VDECS) – a device that achieves diesel PM emission reductions of at least 85 percent – or with a 2004 or newer model-year engine certified to California or federal emission standards. By December 31, 2013, drayage trucks equipped with a 1994 – 2003 model year engine would have to be repowered, replaced, or retrofitted to meet or exceed the 2007 model year California or federal emission standards. To meet the State's SIP commitments, the Board may consider additional PM and NOx emission reduction requirements for 2004-2006 model-year engine equipped trucks. For example, the Board could decide that all trucks used in drayage service meet or exceed 2007 model-year California or federal emission standards.

While the proposal specifies compliance requirements and deadlines for regulated engines, it does not require specific control technologies or methods that owners and operators would be required to use to achieve compliance – i.e., prescriptive requirements that promote the development of alternative compliance strategies and technologies. The Board may decide that prescriptive measure are necessary.

Compliance Extensions

Staff has identified instances where no PM reduction technology is currently verified by ARB for certain model-year truck and engine combinations. To allow time for the development of PM reduction technologies, staff designed a one-year, one-time extension to the Phase 1 December 31, 2009 compliance deadline that could be used by truck owners of affected vehicles. The proposed regulation would allow owners and operators to apply to ARB for an extension of the Phase 1 compliance deadline and, if approved by ARB, they would be granted an extension until December 31, 2010 for compliance. If the December 31, 2010 deadline subsequently arrives and there is still no verified technology available, the truck owner would have to comply by other means – most likely engine repower or truck replacement.

Motor Carriers

The regulation would require motor carriers, among other things, to dispatch only compliant drayage trucks to the ports and rail yards. Motor carriers would also be required to provide a copy of the regulation to each drayage truck owner, check that the truck is registered in the Drayage Truck Registry (DTR), ensure the truck driver has motor carrier contact information, and keep detailed dispatch records. Motor carriers would be required to keep the dispatch records for at least five years and provide copies to enforcement personnel upon request. If determined necessary, the Board may consider additional or alternative requirements for motor carriers to better effectuate the purposes and enforcement of the regulation.

Monitoring, Reporting, and Recordkeeping

The proposed regulation includes reporting and recordkeeping requirements for motor carriers, port terminals, intermodal rail yard facilities, port and rail authorities, and truck owners. Motor carriers would be required to keep dispatch records for five years and terminals and rail yards would be required to keep records of non-compliant trucks entering their facilities for a similar five-year period. The proposed regulation would also require truck owners to register their vehicles in the DTR and keep emission control retrofit maintenance records. Additionally, port and rail yard authorities would be required to summarize non-compliant truck data gathered by the terminals and rail yards and report the results to the ARB. Finally, for enforcement purposes, motor carriers, port terminals, and intermodal rail yards would be required to provide access to ARB employees or officers upon request. If determined necessary, the Board may consider additional or alternative monitoring, reporting and recordkeeping requirements to better effectuate the purposes and enforcement of the regulation.

Drayage Truck Registry

Owners of drayage trucks that operate at ports and intermodal rail yards before September 30, 2009, and who intend to continue such operation after that date would be required to register those trucks in the DTR, as administered by ARB, and affix a DTR compliance label to each truck. After September 30, 2009, a drayage truck that has previously not operated at a port or intermodal rail yard would be required to register in the DTR and have a compliance label affixed before it could commence operations. Using information provided by drayage truck owners, the DTR would record and house pertinent information for each truck, including make, model, engine model year, compliance status of each truck, and owner contact information. After all required information is provided to the DTR, it would issue compliance labels to the drayage truck owners. The compliance label would be used by terminals and rail yards – and ultimately, by enforcement personnel -- to determine compliance status. It would also be used by ARB as an outreach tool.

Right of Entry and Violations

The proposal provides that ARB shall have the right of entry to facilities of port terminals, intermodal rail yards, and motor carriers for purposes of inspection and enforcement. It further provides that any violation of the requirements or other provisions would subject the person or business who committed the violation to the penalties, injunctive relief, and other remedies available under applicable provisions of the Health and Safety Code.

Severability

This proposed regulation provides that if any part of the regulation is held to be invalid, the remainder of the regulation would continue to be effective.

COMPARABLE FEDERAL REGULATIONS

Pursuant to its authority under CAA section 202(a), U.S. EPA has established emission standards for new diesel, alternative fuel, and gasoline on-road heavy-duty engines. (See Title 40, Code of Federal Regulations, Part 86.) U.S. EPA, however, does not have authority to establish emission standards for in-use on-road motor vehicles. Although California must obtain a waiver of federal preemption under CAA section 209(b) before implementing new engine emission standards for new motor vehicles sold in California, no federal preemption exists for requirements regarding in-use motor vehicles and engines adopted by the State.

AVAILABILITY OF DOCUMENTS AND AGENCY CONTACT PERSONS

As noted above, the Board staff has prepared two documents for the proposed regulatory action: a Staff Report, which includes a summary of the economic and environmental impacts of the proposal, and a Technical Support Document, which

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 – Regulation to Control Emissions from In-Use On-Road Diesel-Fueled Heavy-Duty Drayage Trucks." The Technical Support Document is entitled, "Technical Support Document: Technical Support for the Proposed Rulemaking – Regulation to Control Emissions from In-Use On-Road Diesel-Fueled Heavy-Duty Drayage Trucks."

Copies of the Staff Report with the full text of the proposed regulatory language and the Technical Support Document may be accessed on the ARB's web site listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, 1st Floor, Sacramento, CA 95814, (916) 322-2990 at least 45 days prior to the scheduled hearing on December 6, 2007.

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 web site listed below.

Inquiries concerning the substance of the proposed regulation may be directed to the designated agency contact person, Michael Miguel, Manager of the Project Support Section, at (916) 445-4236, or by email at mmiguel@arb.ca.gov.

Further, the agency representative and designated back-up contact persons to whom nonsubstantive inquiries concerning the proposed administrative action may be directed are Alexa Malik, Manager, Board Administration & Regulatory Coordination Unit, (916) 322-4011, and 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 Staff Report, Technical Support Document, and all subsequent regulatory documents, including the FSOR, when completed, are also available on the ARB Internet site for this rulemaking at www.arb.ca.gov/regact/2007/drayage07/drayage07.htm

IMPACTS TO PUBLIC AGENCIES AND TO REPRESENTATIVE BUSINESSES AND PRIVATE PERSONS

Impacts to Businesses and Private Individuals

Pursuant to Government Code section 11346.5(a)(9), the Board's Executive Officer has determined that the proposed regulation could have an adverse economic impact to representative businesses and private persons.

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.

The total regulation cost results from the early retirement or replacement of drayage trucks, the addition of VDECS, and the meeting of reporting and recordkeeping requirements. These costs are the estimated out-of-pocket costs to truck owners, which could include lost wages while a truck is unavailable awaiting purchase or retrofit. Truck owner costs could be substantial and could directly affect their ability to continue drayage operations at California's ports and intermodal rail yards. A detailed economic analysis is provided in the Staff Report and Technical Support Document. Additionally, motor carriers, port and rail authorities, terminal operators, and rail yard operators would incur annual recordkeeping and reporting compliance costs associated with increased labor wages.

California businesses may be affected by the proposed annual cost of the regulation to the extent that the implementation of the proposed regulation reduces their profitability. Staff evaluated the economic impact of complying with the requirements of the proposed regulation on California's economy using the E-DRAM model. The results of this analysis indicate that the impacts of the proposed regulation would be small compared to the growth that is expected to occur in California.

Based on the modeling, the Executive Officer has made an initial determination that the proposed regulatory action may have a significant statewide adverse economic impact directly affecting businesses, including the ability of California businesses to compete with businesses in other states, or on representative private persons. While the Executive Officer does not believe that the added costs of the proposed regulations are high enough for terminal operators or rail yard operators to consider alternate ports or rail yards outside of California, a number of businesses are integrally linked to California ports and intermodal rail yards and these businesses may be adversely affected, as explained below. The ARB staff has considered proposed alternatives that would lessen any adverse economic impact on businesses and invites you to submit proposals. Submissions may include the following approaches for consideration:

(i) 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) Use of performance standards rather than prescriptive standards.
(iv) Exemption or partial exemption from the regulatory requirements for businesses.

Alternatives that staff considered are described in more detail in the Staff Report and the Technical Supporting Document.

In accordance with Government Code sections 11346.3 and 11346.5(a)(10), the Executive Officer has determined that the proposed regulatory action may 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. Some

businesses that provide used trucks or the manufacture and installation of emission retrofit controls could expand due to the volume of business created by the regulatory requirements.

The Executive Officer has also determined, pursuant to title 1, CCR, 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 regulations which apply to businesses are necessary for the health, safety, and welfare of the people of the State of California.

In accordance with HSC sections 43013(a) and (b), the Executive Officer has determined that the standards and other requirements in the proposed regulations are necessary, cost-effective, and technologically feasible for diesel engines on drayage trucks operated at California's ports and intermodal rail yards.

Before taking final action on the proposed regulatory action, the Board must determine, pursuant to Government Code section 11346.5(a)(13), 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 not create significant costs to State and local agencies 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 Government Code, or other nondiscretionary cost or savings to state or local agencies. The State and local agencies affected are the port authorities which are responsible for collecting and relaying data to the ARB. ARB Staff estimates these costs are the same costs that would be applied to other similarly situated stakeholders in the private sector and would be minor and able to be absorbed under existing budgets.

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 in writing or by e-mail before the meeting. To be considered by the Board, written comments submissions not physically submitted at the meeting must be received **no later than 12:00 noon, Pacific Standard Time, December 5, 2007,** and 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
- Facsimile submittal: (916) 322-3928

Please note that under the California Public Records Act (Government Code section 6250 et seq.), written and oral comments, attachments, and associated contact information (e.g., 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 30 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 39600, 39601, 39650, 39658, 39659, 39665, 39666, 39667, 39674, 39675, 42400, 42400.1, 42400.2, and 42402.2, 42410, 43013, 43016, 43018, 43023, and 43701. This action is proposed to implement, interpret, or make specific Health and Safety Code sections 39600, 39601, 39650, 39658, 39659, 39666, 39667, 39674, 39675, 42400, 42400.1, 42400.2, and 42402.2, 42410, 43013, 43016, 43018, 43023, and 43600.

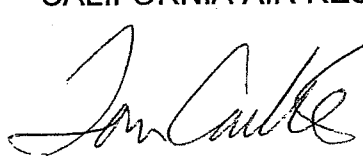
HEARING PROCEDURES

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 section 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 the ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, 1st Floor, Sacramento, CA 95814, (916) 322-2990.

CALIFORNIA AIR RESOURCES BOARD



Tom Cackette
Acting Executive Officer

Date: October 9, 2007

California Environmental Protection Agency
AIR RESOURCES BOARD

STAFF REPORT:
INITIAL STATEMENT OF REASONS FOR
PROPOSED Rulemaking

PROPOSED REGULATION FOR DRAYAGE TRUCKS

Stationary Source Division
Project Assessment Branch

October 2007

State of California
AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR THE PROPOSED RULEMAKING

Public Hearing to Consider

REGULATION TO REDUCE EMISSIONS FROM HEAVY-DUTY ON-ROAD DRAYAGE TRUCKS IN CALIFORNIA PORT AND INTERMODAL RAIL SERVICE

To be considered by the Air Resources Board on December 6 and 7, 2007, at:

Air Resources Board
Auditorium
9530 Telstar Avenue
El Monte, California 91731

Stationary Source Division
Robert Fletcher, Chief
Robert Barham, Ph.D., Assistant Chief

Project Assessment Branch
Michael J. Tollstrup, Chief

Health and Exposure Assessment Branch (RD)
Linda Smith, Ph.D., Chief

Mobile Source Analysis Branch (PTSD)
Michael Benjamin, D. Env, Chief

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

REGULATION TO REDUCE EMISSIONS FROM HEAVY-DUTY ON-ROAD DRAYAGE TRUCKS IN CALIFORNIA PORT AND INTERMODAL RAIL SERVICE

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EXECUTIVE SUMMARY

The California Air Resources Board (ARB or Board) staff is proposing a regulation to reduce diesel particulate matter (PM) and oxides of nitrogen (NOx) emissions from drayage trucks operating at California's ports and rail yards. The proposed Drayage Truck Regulation (regulation) is part of ARB's ongoing efforts to reduce PM and NOx emissions from diesel-fueled engines and improve air quality associated with goods movement. In addition, the regulation also provides green house gas benefits and is designed to support local emission reduction goals such as the Clean Air Action Plan by the ports of Los Angeles and Long Beach and the Comprehensive Truck Management Plan by the Port of Oakland. A copy of the proposed regulation is provided in Appendix A of this report. (SPB – CAAP, 2006) (CAAPTech, 2006)

Drayage trucks are on-road, diesel-fueled, heavy-duty trucks that transport containers, bulk, and break-bulk goods to and from the ports and intermodal rail yards as well as to many other locations. Staff estimates that there are approximately 100,000 drayage trucks statewide, of which approximately 20,000 frequently service the ports and rail yards. This segment of the drayage fleet consists largely of independent owner / operators and staff estimates that approximately 80 percent of such drayage trucks are operator owned. Currently, about 3 tons per day (tpd) of diesel PM and 61 tpd of NOx are emitted from drayage trucks due to moving goods to and from California's ports and intermodal rail yards.

Diesel PM was identified as a toxic air contaminant in 1998. Long-term exposures to diesel PM increase the risk of developing lung cancer. Non-cancer impacts, including premature death and respiratory disease, are associated with exposure to directly emitted diesel PM and secondary diesel PM formed when NOx emissions from diesel engines react in the atmosphere to form nitrates. Additionally, NOx emissions contribute to the formation of regional ozone and its associated adverse health effects such as: reduced lung function, increased respiratory symptoms, increased airway hyper-reactivity, and increased airway inflammation.

The purpose of the proposed regulation is to reduce the near-source and regional health risks caused by elevated levels of diesel PM emissions and reduce regional exposures to ozone and secondary PM through NOx emission reductions. The regulatory goals focus on reducing diesel PM as expeditiously as possible and meet, in particular, $PM_{2.5}$ standards in the South Coast by 2014.

The proposed regulation includes requirements for trucks in drayage service and establishes emission standards that may require the installation of ARB certified retrofit technologies, the use of trucks meeting more recent California and federal emission standards (emission standards), or both. The proposal would also establish recordkeeping and reporting requirements for drayage truck owners, motor carriers, port terminal operators, rail yard operators, and port and rail authorities.

The proposed regulation sets two distinct compliance deadlines that will affect virtually all drayage trucks that currently move containers and certain other goods to and from ports and intermodal rail yards. First, by December 31, 2009 (Phase 1), all pre-1994 model year (MY) engines are to be retired and / or replaced with 1994 and newer MY engines. Furthermore, all trucks with 1994 – 2003 MY engines would be required to achieve an 85 percent PM emission reduction through the use of an ARB approved level 3 verified diesel emission control strategy (VDECS)[1] (ARBver, 2002). Secondly, by December 31, 2013 (Phase 2), all trucks with 1994 – 2003 MY engines would be required to further reduce emissions to meet the 2007 MY emission standards. Phase 2 of the proposed regulation is designed, in part, to ensure that the NOx emission reductions critical to attainment of federal standards in the South Coast and San Joaquin Valley Air Basins occurs on the needed schedule.

The proposed regulation applies to any person who owns or operates a diesel-fueled drayage truck having a gross vehicle weight rating greater than 33,000 pounds that operates at specified California ports, intermodal rail yards, or both. Under the proposed regulation, owners and operators of drayage trucks equipped with 2004 through 2006 certified model year engines (2004 emission standard engines) would be subject to the monitoring, recordkeeping, reporting, and registry requirements of this regulation. However, the proposed regulation would not specify engine replacement or retrofit requirements for this group of drayage trucks. The engine replacement / retrofit requirements will be established for this group of drayage trucks in the forthcoming regulation for in-use, on-road, diesel-fueled, fleets to be considered by the Board in 2008.

Under the proposed regulation, all drayage trucks involved in work at affected ports and rail yards would be registered in a drayage truck registry (DTR) by late 2009 and would be required to affix a compliance label to the driver's side door. Only compliant trucks would be issued a registry label. Motor carriers would be required to only dispatch trucks with a valid DTR label or face enforcement action. Terminal and rail yard operators would be required to report all trucks entering their facilities without a valid DTR label to their respective port or rail authority according to a set schedule. This information would then be forwarded to ARB enforcement for action against the motor carrier (for dispatching non-compliant truck(s)).

Staff estimates that currently about 28 percent of drayage trucks in service are pre-1994 MY, 68 percent are MY 1994 – 2003, and 4 percent are MY 2004 and newer. To comply with Phase 1, all pre-1994 MY trucks would need to be replaced with 1994 and newer MY trucks and have installed a level 3 VDECS, unless the replacement truck has a 2004 or newer engine. Staff believes that most MY 1994 – 2003 trucks will be retrofitted with a level 3 VDECS rather than be replaced with 2004 and newer emission standard compliant trucks. To comply with Phase 2, staff believes that pre-2004 emission standard compliant trucks will be replaced with MY 2007 and newer vehicles. The possible introduction of new emission reduction technologies could provide other

[1] Title 13, CCR, Section 2700 – 2710. ARB's Verification Program.

compliance pathways and could significantly reduce the costs of the proposed regulation.

In 2010, after full implementation of Phase 1, diesel PM emissions from drayage trucks would be reduced from baseline 2007 levels by nearly 2.6 tpd (86 percent reduction), and NOx emissions would be reduced by approximately 2 tpd (3 percent reduction). In 2014, after full implementation of Phase 2, NOx emissions would be reduced from baseline 2007 levels by nearly 34 tpd (56 percent reduction) with some additional PM reductions. The emission reductions from the proposed regulation would result in lower ambient PM levels and reduced exposure to diesel PM. The reduction in potential cancer risk was assessed for a heavily traveled segment of the I-710 freeway near the ports of Los Angeles and Long Beach. Based on the overall projected reduction in drayage truck PM emissions, staff estimates a greater than 75 percent reduction in potential cancer risks depending on the distance from the freeway. Additionally, staff estimates that approximately 580 premature deaths statewide would be avoided by year 2014 from implementation of the proposed regulation. Staff also estimates that the proposed rule will reduce carbon dioxide (CO_2) emissions. CO_2 emissions from vehicles are directly proportional to fuel consumption. Phase 1 of the proposed regulation requires fleet owners to replace pre-1994 MY trucks (mechanical fuel injection) with 1994 or newer vehicles (electronic fuel injection). Trucks with electronic fuel injection achieve better fuel economy (4.5 miles per gallon for mechanical fuel injection versus 6.0 miles per gallon for electronic fuel injection) and as a result, staff estimates a diesel fuel savings of 11 million gallons per year. This fuel savings is expected to reduce carbon dioxide emissions by approximately 7 percent.

Staff estimates that the costs to comply with the proposed regulation would be approximately $1.1 - $1.5 billion (2006 dollars). The costs are the incremental costs of regulation compliance and include those costs associated with the early replacement of trucks (the residual value of the truck being replaced), retrofit aftertreatment installation and maintenance costs, and recordkeeping and reporting costs. Staff has estimated initial Phase 1 costs of $10,000 to $31,000 per truck (2006 dollars) for retrofit and/or replacement and initial Phase 2 net costs of approximately $33,000 (2006 dollars) for truck replacement, which could create an economic hardship.

Staff is proposing to use Proposition 1B funds to help with the initial costs of Phase 1 and reduce the economic hardship on truck owners. It is expected that 1B funds would be used to co-fund the cost of a PM retrofit device or purchase a 2007 MY or newer truck. The use of bond funds would help to greatly accelerate implementation and significantly reduce diesel impacts to surrounding communities.

Staff evaluated the economic impact of complying with the requirements of the proposed regulation on California's economy using the E-DRAM model. The results of this analysis indicates the gross state output would be reduced by $650 to $870 million (less than 0.03 percent) and personal income would be reduced by roughly $220 million (less than 0.02 percent) in 2013. California employment would be reduced by 2,400 to 3,300 (less than 0.02 percent) in 2013. Therefore, the impacts of the proposed

regulation are small compared to the growth that is expected to occur in California over the next 7 years. In addition, the value of the health benefits of the proposed regulation is substantial, and significantly exceeds the direct costs. The estimated economic value of the avoided premature deaths and other health benefits due to the emission reductions are estimated to range from $3.5 (discounted at 7 percent) to $4.3 billion (discounted at 3 percent).

Staff has determined that multiple local, State, and federal agencies could be impacted by the proposed regulation. To the extent that these agencies are responsible for port or rail operations, they would be responsible for collecting and collating truck entry information from the terminals and rail yards and relaying it to the ARB. ARB staff estimates costs would be relatively small and could be absorbed within current budgets.

The ARB would also be the primary enforcement agency and would need an estimated additional four (4) staff to perform compliance inspections and audits at a cost of approximately $400,000 per year. Additionally, staff estimates total ARB outreach costs would be approximately $110,000.

Staff estimated the cost effectiveness by assuming that all costs for complying with Phase 1 would be attributable to PM emission reductions and all costs for Phase 2 compliance would be attributable to NOx emission reductions, which resulted in a PM cost effectiveness range of $57 - $77 per pound and NOx cost effectiveness range of $6 - $8 per pound. The cost effectiveness for this proposed regulation is consistent with the Public Fleets Rule PM cost effectiveness of $160 per pound and NOx cost effectiveness of approximately $9[2] per pound, which the Board approved in 2005.

Staff crafted the proposed regulation to postpone Phase 2 (2007 engine requirements) as long as possible to minimize used truck prices. In addition, this will allow time for the development of new (and potentially less expensive) emission reduction technologies and give truck owners financial planning lead time. However, the timely attainment of federal standards in the San Joaquin Valley and South Coast Air Basins necessitate very substantial NOx reductions by 2014 to meet SIP obligations. Staff believes the 2013 compliance requirements are attainable and that sufficient lead-time has been provided for industry to generate a solution (e.g. drayage rate structure changes) that would enable truck owners to afford compliance.

Staff believes that supplemental funding (such as is available from Proposition 1B monies), a change in the drayage rate fee structure, or both will be critical in allowing many current truck owners to meet the requirements of the proposed regulation. In implementing the proposed regulation, it is expected that staff would work with the ports, terminal and rail yard operators, shippers, local districts, and other parties to secure funding to both accelerate compliance and ensure that the emission targets are met without an interruption in drayage service throughout the State. Staff will update the Board on progress in this regard and may consider proposing amendments to the

[2] Combined HC + NOx

proposed regulation for the Board's consideration if substantial problems are occurring and changes are needed to successfully implement the program.

Potential funding mechanisms include a number of federal and State programs that may be utilized by program administrators or truck owners. Funding programs include: The Congestion Mitigation and Air Quality Improvement Program (U.S. Department of Transportation) which provides funding to state and local governments to support transportation projects as well as programs to improve air quality and reduce traffic congestion; The U.S. EPA's National Clean Diesel Campaign which offers funding and technical assistance to foster the adoption of cleaner diesel technologies and strategies; The Carl Moyer grant program that is implemented by a partnership between the ARB and local air districts; and Proposition 1B which will fund projects that reduce air pollution and consequently the resulting health risk associated with freight movement along California's trade corridors. An expanded discussion of these programs is provided in the Technical Support Document.

1. INTRODUCTION

This Initial Statement of Reasons (Staff Report) presents an evaluation of the need for emission reductions from drayage trucks. The evaluation includes corresponding health impacts, a summary of the proposed regulation, and the projected emissions reductions along with the associated reduction in health risk. The estimated costs for regulation compliance are presented, for both industry and State and local governments, along with the alternative proposals considered. A copy of the proposed regulation is provided in Appendix A. The Technical Support Document (TSD), an addendum to the Staff Report, provides more detailed analyses of these subjects and supporting documentation for the proposal. The TSD is provided under separate cover.

The California Air Resources Board's (ARB or Board) mission is to protect public health, welfare, and ecological resources through the effective and efficient reduction of air pollutants, while recognizing and considering the effects on the economy of the State. The ARB's vision is that all individuals in California, especially children and the elderly, can live, work, and play in a healthful environment – free from harmful exposure to air pollution. To help achieve this, ARB has adopted numerous regulations to control emissions from many different sources, including diesel engines. Diesel engine exhaust is a significant health concern because it is a source of unhealthful air pollutants including gaseous and particulate-phase toxic air contaminants (TAC), particulate matter (PM), oxides of nitrogen (NOx), carbon monoxide, and hydrocarbons.

In 1998, the Board identified diesel PM as a TAC with no Board-specified threshold exposure level, pursuant to Health and Safety Code (HSC) sections 39650 through 39675 (ARB, 1998). A needs assessment for diesel PM was conducted between 1998 and 2000 pursuant to HSC sections 39658, 39665, and 39666. This resulted in ARB staff developing and the Board approving the *Risk Reduction Plan to Reduce Particulate Matter Emissions from Diesel-Fueled Engines and Vehicles* (Diesel RRP) in 2000. The Diesel RRP presented information on the available options for reducing diesel PM and recommended regulations to achieve these reductions. The plan's scope was broad, addressing all categories of mobile and stationary engines. It included recommendations for the development of control measures for diesel sources, such as those covered by the proposed regulation. The ultimate goal of the Diesel RRP is to reduce, by 2020, California's diesel PM emissions and associated cancer risks by 85 percent from the 2000 levels. (ARB, 2000)

In April 2006, the Board approved the *Emission Reduction Plan for the Ports and Goods Movement in California* (Plan). The Plan identifies strategies for reducing emissions created from the movement of goods through California ports and into other regions of the State. The Emission Reduction Plan is part of the broader Goods Movement Action Plan being jointly carried out by the California Environmental Protection Agency and the Business, Transportation, and Housing Agency (ARB, 2006). Phase I of the Goods Movement Action Plan (GMAP) was released in September 2005, and highlighted the air pollution impacts of goods movement and the urgent need to mitigate localized health risk in affected communities. The final GMAP was released in January 2007 and

includes a framework that identifies the key contributors to goods movement-related emissions.

The Plan identifies numerous strategies for reducing emissions from all significant emission sources involved in goods movement, including ocean-going vessels, harbor craft, cargo handling equipment, locomotives, and trucks. The Plan establishes emission reduction goals for drayage trucks including modernizing (replacing and/or retrofitting) port trucks, implementing California and federal 2007 truck emission standards, and restricting entry of trucks new to port service unless equipped with diesel PM controls. The proposed regulation would represent a significant first step toward satisfying the Emission Reduction Plan goals. (BTH & CalEPA, 2007)

The federal Clean Air Act (CAA) requires U.S. EPA to establish National Ambient Air Quality Standards (NAAQS) for pollutants considered harmful to public health, including fine particulate matter ($PM_{2.5}$) and ozone. Set to protect public health, the NAAQS are adopted based on a review of health studies by experts and a public process. Ambient $PM_{2.5}$ is associated with premature mortality, aggravation of respiratory and cardiovascular disease, asthma exacerbation, chronic and acute bronchitis and reductions in lung function. Ozone is a powerful oxidant. Exposure to ozone can result in reduced lung function, increased respiratory symptoms, increased airway hyper-reactivity, and increased airway inflammation. Exposure to ozone is also associated with premature death, hospitalization for cardiopulmonary causes, and emergency room visits for asthma.

Areas in the State that exceed the NAAQS are required by federal law to develop State Implementation Plans (SIPs) describing how they will attain the NAAQS by certain deadlines. The NOx emission reductions are needed because NOx leads to formation in the atmosphere of both ozone and $PM_{2.5}$; diesel PM emission reductions are needed because diesel PM contributes to ambient concentrations of $PM_{2.5}$.

The South Coast Air Quality Management District (SCAQMD) and the San Joaquin Valley Air Pollution Control District (SJVAPCD) are designated as nonattainment of both the federal 8-hour ozone and federal PM2.5 NAAQS. In order to demonstrate that the necessary emission control programs are in place, the U.S. EPA requires that all necessary emission reductions be achieved by 2014 for PM2.5 and 2023 for ozone.

In both the South Coast and San Joaquin Valley air basins significant reductions of NOx are crucial to meet the federal standards. For example, at this time, the strategy to achieve attainment of the $PM_{2.5}$ standards in the South Coast Air Basin includes staff estimates that a 55 percent reduction in NOx emissions from 2006 levels (i.e., a total reduction of hundreds of tons per day) and a 15 percent reduction in direct $PM_{2.5}$ emissions from 2006 baseline levels will be necessary for attainment of the $PM_{2.5}$ standards in the South Coast Air Basin. The NOx emission reductions from the proposed regulation would play an essential role in assisting the South Coast Air Basin with meeting its 2014 $PM_{2.5}$ deadline as well as its future ozone deadlines.

The federal CAA permits states to adopt more protective air quality standards and California has set standards for particulate matter and ozone that are more protective of public health than respective federal standards. The Bay Area, South Coast, San Joaquin Valley, and San Diego areas are nonattainment for the State standards for ozone and $PM_{2.5}$. HSC section 40911 requires the local air districts to submit plans to the Board for attaining the State ambient air quality standards, and HSC section 40924 requires triennial updates of those plans. The NOx and $PM_{2.5}$ emission reductions from the proposed regulation will assist the local air districts in achieving attainment of the State ambient air quality standards.

Staff is proposing a regulation to reduce diesel PM and NOx emissions from trucks in drayage service at California's ports and intermodal rail yards. The regulation would significantly reduce diesel PM emissions by the end of 2009. Diesel PM emission reductions are needed to reduce premature mortality, cancer risk, and other adverse impacts from exposure to this TAC especially in heavily impacted communities near major ports and rail yards. By 2014, staff projects that drayage truck diesel PM emissions would be reduced about 86 percent and NOx emissions about 56 percent from the 2007 baseline. These emission reductions would occur in areas on and near ports and rail yards, along the major truck roadway arteries leading into the ports and rail yards, and in those communities surrounding these areas, as well as further inland.

The regulation would also reduce diesel PM and NOx emissions that contribute to exceedances throughout the State of ambient air quality standards for both $PM_{2.5}$ and ozone. These reductions would assist California in its goal of achieving state and federal air quality standards.

2. EMISSIONS INVENTORY

Drayage Truck Population

The proposed regulation would affect drayage trucks that currently service California's ports and intermodal rail yards. Of these, approximately 20,000 trucks service the ports or intermodal rail yards regularly, on average several times a week or more. These are defined as frequent and semi-frequent trucks and are responsible for a large majority of port and rail yard drayage truck emissions. Another estimated 80,000 drayage trucks service ports and rail yards much less frequently, and derive the bulk of their revenues from drayage services to other locations. As expected, a large majority of drayage trucks operate at the ports of Los Angeles and Long Beach. The third largest population operates at the Port of Oakland with the rest spread among the remaining ports and rail yards. Tables 1 and 2 show port and rail yard drayage truck populations by frequency.

Table 1: Port Drayage Truck Populations (2007)

Facility Name	Number of Frequent & Semi-Frequent Trucks	Total Number of Trucks (Including Non-Frequent)
Los Angeles	13,800	55,000 – 90,000
Long Beach		
Oakland	2,800	8,000
San Diego	300	900
Hueneme	100	300
San Francisco	100	300
Redwood City	100	200
Richmond	Dedicated Car Carriers	Dedicated Car Carriers
Humboldt Bay (Eureka)	40	100
Crockett	50	100
Pittsburgh	50	100
Stockton	200	500
Sacramento	40	100
Benicia	10	20
Total	**~18,000**	**~66,000 - 101,000**

Table 2: Intermodal Rail Yard Drayage Truck Populations (2007)

Facility Name	Number of Frequent & Semi-Frequent Trucks	Total Number of Trucks (Including Non-Frequent)
Oakland UP	150	450
Hobart BNSF	1,000	3,300
LATC UP	300	1,100
Commerce UP	500	1,700
Richmond BNSF	100	400
Commerce Eastern BNSF	400	1,300
ICTF UP*	0	0
San Bernardino	700	2,400
Stockton Intermodel BNSF	250	800
Lathrop Intermodel UP	200	700
Oakland BNSF *	0	0
Total	**3,600**	**12,000**

*ICTF UP in Los Angeles and BNSF in Oakland handled only port container traffic. The trucks are included in the port inventories shown in Table 1.

Drayage Truck Age Distribution

To determine the age distribution of the drayage trucks visiting the Los Angeles and Long Beach ports, staff analyzed the optical character recognition (OCR) data collected by the ports. Optical character recognition data is captured by utilizing equipment which optically scans and records characters (in this case, license plate information) from trucks entering terminals. Staff then compared the license plate information with the Department of Motor Vehicle data base and developed an age distribution for the trucks servicing the ports. Similar methodologies were utilized to generate age distributions for the Port of Oakland and rail yards (See the Technical Supporting Document (TSD) for further analysis). No license plate data were available for the remaining ports and staff assumed they would have the same age distributions as the Port of Oakland. The age distributions revealed the drayage truck fleet has an average age of 13 years, which differs slightly from the average age of 12 years seen in the overall fleet of California registered. Table 3 below shows the overall estimated age distribution and percent of the population for all affected ports and intermodal rail yards.

Table 3: 2007 Drayage Truck Age Distribution

Model Year	Percent of Population
2007	<1%
2004-2006	4%
1994-2003	68%
Pre-1994	28%

The proposed regulation affects on-road, diesel-fueled, class-8 trucks (trucks with a gross vehicle weight rating greater than 33,000 pounds) in frequent intermodal drayage service. These trucks comprise about 10 percent of the statewide California registered Class-8 truck fleet and generate about 6 percent of the NOx emissions and about 7 percent of the PM emissions. ARB staff estimates that about 70 percent of NOx and 74 percent of PM emissions from drayage trucks are in the SCAQMD. Furthermore, about 10 percent of all NOx and 6 percent of all PM drayage truck emissions are in the Bay Area Air Quality Management District (BAAQMD), and approximately 11 percent of NOx and 10 percent of PM drayage truck emissions are in the SJVAPCD. The remaining emissions are distributed over other districts with affected ports and rail yards (see Table 4).

Table 4: Drayage Truck Emissions Inventory (2007)

Location	2007 Pollutant Emissions, Tons/Year	
	PM	NOx
SCAQMD	630	12,000
BAAQMD	50	2,000
San Joaquin Valley	90	2,000
Rest of State	80	2,000
Total	**850**	**18,000**

3. HEALTH RISK AND BENEFITS

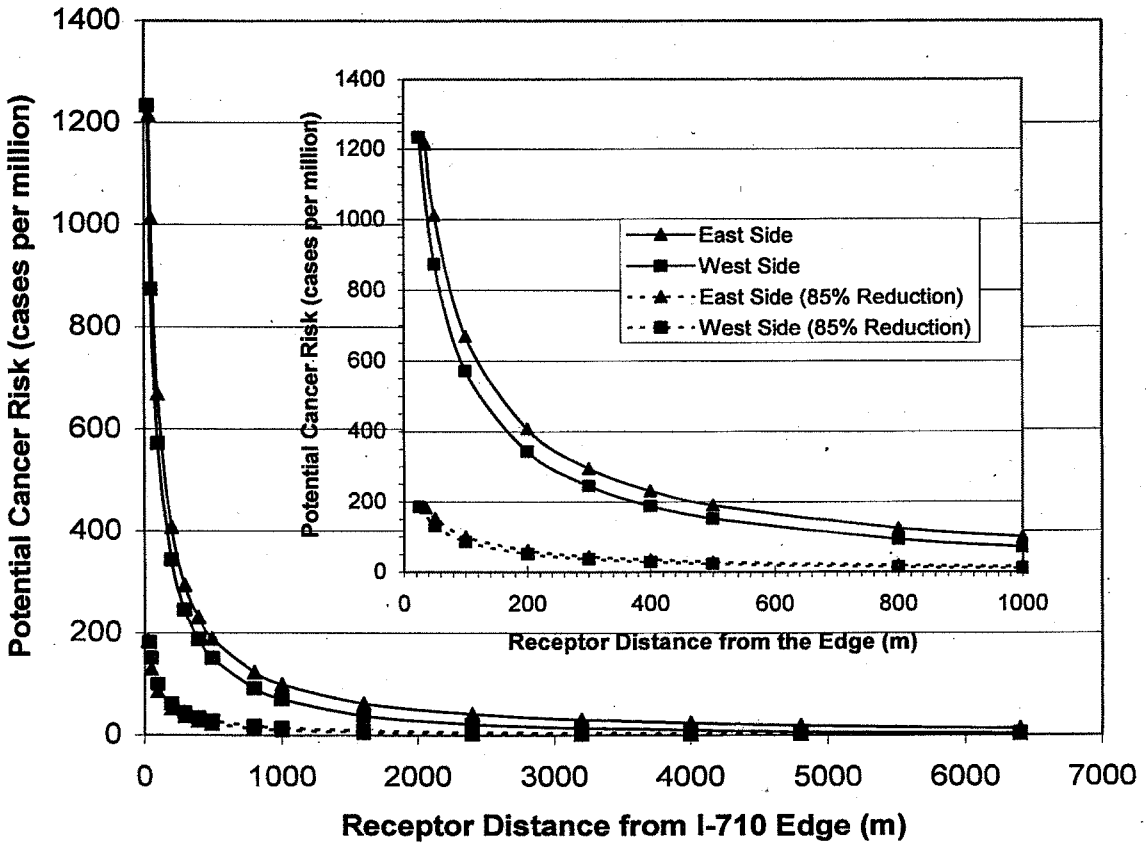
In April 2006, ARB staff published a risk assessment for the Ports of Los Angeles and Long Beach (POLA/LB). The POLA/LB health risk assessment estimated that in-port drayage trucks emissions are a relatively small (three percent of all port specific emissions) when compared to other sources at the ports (ships, cargo handling craft etc.). The analysis shows that the in-port drayage truck ground-based localized impacts of 100 to 200 in a million occurs on port property and exposure risk levels to nearby residents are small. (ARB-POLA-POLB HRA, 2006) However, as this analysis does not include drayage truck emissions released beyond the port's boundaries, staff estimated off-port drayage truck emission health impacts in a subsequent localized health risk assessment detailed below.

To estimate the health risks associated with drayage truck activities in local communities, staff conducted a health risk assessment to determine the 70-year potential cancer risk associated with exposures to diesel PM emissions from drayage trucks operating on the I-710 freeway near the ports of Los Angeles (POLA) and Long Beach (POLB). The I-710 freeway is a major thoroughfare for drayage trucks. Staff believes that the results from this analysis are generally applicable to other California freeways near maritime ports.

To estimate the potential cancer risks from port trucks operating along the I-710 freeway, staff conducted air dispersion modeling to estimate the ambient concentrations of diesel PM as a function of the total diesel truck traffic, speed, and emissions per mile traveled along a one mile freeway segment. The potential cancer risks were then estimated using standard risk assessment procedures.

Figure 1 shows the potential cancer risks to nearby receptors between 25 to 6,400 meters from the edge of the I-710 freeway for each side along the east-west direction (solid lines). The two curves represent risks on the west and east sides of the I-710 freeway as a function of distance from the freeway. Figure 1 also shows that the implementation of the proposed regulation will reduce the public's exposures to diesel PM emissions and the potential cancer risks associated with those exposures (dashed lines).

Figure 1. Potential Cancer Risks from Diesel Truck Operations from Freeway I-710



This analysis estimates that the cancer risk is greater than 500 in a million for areas paralleling and within 200 meters of the freeway. The risk level drops off fairly quickly as the distance from the freeway increases. At 2,000 meters from the freeway, the risk levels fall below 50 in a million. The 10 in a million risk contours occurs at approximately the 4,000 – 7,000 meters from the freeway, depending on the side of the freeway.

The overall health benefits of implementing the proposed regulation are substantial. Staff estimates that the cumulative emissions reductions over the lifetime of the rule can be associated with approximately:

- 580 fewer premature deaths
- 120 fewer hospital admissions due to respiratory causes
- 230 fewer hospital admissions due to cardiovascular causes
- 17,000 fewer cases of asthma-related and other lower respiratory symptoms
- 1,400 fewer cases of acute bronchitis
- 100,000 fewer work loss days
- 580,000 fewer minor restricted activity days.

The uncertainty behind each estimated benefit ranges from about 15 to 75 percent for most endpoints. The estimated value of these health benefits over 2010 to 2014 from these reductions in adverse health effects is nearly $3.5 billion using a 7 percent discount rate or about $4.3 billion using a 3 percent discount rate. A detailed analysis is provided in the Technical Support Document.

4. SUMMARY OF THE PROPOSED REGULATION

Pursuant to its authority under HSC sections 39650 through 39667, 43013, 43018 and 43601, the Board is authorized to adopt the proposed drayage truck regulation that would apply to the emissions from all class-8 drayage trucks operating at California's ports and intermodal rail yards. The following sections provide more details about the proposed regulation.

A. Regulatory Requirements

The regulation would set requirements in two phases (listed below) for drayage trucks that operate at California ports and intermodal rail yards located within 80 miles of ports. By December 31, 2009, Phase 1 of the emission limits would achieve substantial near-term PM reductions to reduce adverse health affects in nearby local communities. Phase 2 of the limits would achieve additional emission reductions by December 31, 2013 that is necessary for the State to meet its SIP commitments in federal non-attainment areas. The South Coast and San Joaquin Valley air basins are both designated as nonattainment of the federal 8-hour ozone and federal PM2.5 National Ambient Air Quality Standards. Significant reductions of NOx are crucial to meet the federal standards for PM2.5 by 2014 and ozone by 2023.

The regulation would also set requirements for port and rail authorities, port terminal operators, motor carriers, truck owners and drivers, and potentially other businesses located on port and rail yard property.

1. Drayage Trucks

Phase 1: By December 31, 2009, all drayage trucks must be equipped with:

(A) 1994 – 2003 model year engine certified to California and federal emission standards and a level 3 VDECS;

or,

(B) 2004 or newer model year engine certified to California and federal emission standards.

Phase 2: By December 31, 2013, all drayage trucks must be equipped with an engine that:

(A) meets or exceeds 2007 model year California and federal heavy-duty diesel-fueled on-road emission standards;

or,

(B) is certified to 2004 or newer model year California and federal emission standards.

Staff is proposing that emission requirements for the 2004 emission standard compliant trucks (MY 2004 to 2006) be established under the general private fleets' rule that is currently under development by ARB staff. This would allow additional time to investigate several promising PM retrofit technologies that may be available in the near term to reduce PM emissions from these trucks.

The proposal also includes reporting and recordkeeping requirements for port and rail authorities, port terminal and intermodal rail yard operators, motor carriers, and truck owners as discussed earlier. All recordkeeping and reporting requirements are necessary and specifically designed to aid enforcement and to ensure the success of the proposed regulation.

2. Truck Owners

Under the proposed regulation, truck owners engaged in port or rail yard operations would be responsible for ensuring that their trucks meet all emission requirements prescribed by the regulation. This responsibility would include any financial outlay necessary to purchase and install retrofits or purchase new trucks. Owners would also be responsible for ensuring that their trucks are registered in the Drayage Truck Registry (DTR), as administered by the State. Additionally, the regulation would require owners to ensure that their emission control devices are properly maintained and that they keep a VDECS maintenance log in the truck at all times. They would also be responsible (in addition to the driver and motor carrier) for ensuring that the driver is able to present motor carrier contact information upon request. Truck owners may be subject to financial penalties for any non-compliance.

3. Truck Operators

Upon request, drayage truck operators (drivers) engaged in port or rail yard operations would be responsible for presenting to enforcement personnel all motor carrier contact information that they have been provided by dispatching motor carriers and, if applicable, the VDECS maintenance log that drayage truck owners are required to have on-board the truck. As motor carriers are responsible for dispatching compliant trucks and may be fined for not doing so, the truck driver's responsibility for presenting motor carrier information is critical in tracking a non-compliant truck back to the dispatching

carrier. As stated, the maintenance log is the primary responsibility of the truck owner, but the regulation would require that the driver has the responsibility of presenting it upon request. Truck operators may be fined for non-compliance.

4. Motor Carriers

Motor carriers are the conduit through which virtually all drayage trucks are dispatched. The regulation would assign motor carriers with the primary responsibility for ensuring that compliant drayage trucks are dispatched to the ports and intermodal rail yards. To ensure the truck is compliant, each motor carrier would be required check that the truck is registered and current in the drayage truck registry (DTR), which is explained in more detail below. Checking registry status provides a method for the motor carrier to easily determine the compliance status of any drayage truck. To aid in outreach and help ensure that truck owners are apprised of the regulatory requirements, motor carriers would be required to provide a copy of the regulation or an ARB approved summary to each drayage truck owner. Similar to the truck owner requirements mentioned above, the motor carrier would also be required to ensure the truck operator has the motor carrier's contact information at all times while engaged in drayage truck service.

Motor carriers would be required to keep records of all trucks they dispatch to the ports and rail yards for at least five years. This recordkeeping requirement is designed to aid enforcement efforts by providing a paper trial that can be audited for compliance. Motor carriers may be subject to financial penalties for any non-compliance.

5. Port Terminal and Rail Yard Operators

As previously stated, motor carriers would be required to dispatch compliant trucks. To ensure compliance, terminal and rail yard operators would be required to collect and submit information on each truck that does not display a DTR compliance label (non-compliant truck). Every three months, the non-compliant truck information would be sent from the terminal or rail yard to the port or rail authority. Terminal and rail yard operators would be required to keep these records for a minimum of five years.

The terminals and rail yards would not be required to turn around non-compliant trucks – just collect required information for ARB enforcement. ARB staff expects this information to be used in the initial stages as an outreach tool to inform stakeholders of their responsibilities under the proposed regulation. After the outreach stage, the non-compliant truck information is expected to be used to target non-compliant trucks and motor carriers with increasingly more stringent penalties and other actions necessary to ensure compliance. Port terminals and rail yards may be subject to penalties for non-compliance with these responsibilities.

6. Port and Rail Authorities

Port and rail authorities are responsible for gathering all the non-compliant truck information from their terminals or rail yards and then relaying that information to the ARB according to a prescribed schedule and in a prescribed format. Port authorities and rail authorities may be subject to penalties for non-compliance with these responsibilities.

B. Drayage Truck Registry

Beginning January 1, 2010, any truck entering a port or intermodal rail yard must have a DTR label in order to show compliance with the proposed regulation. Drayage truck owners that presently operate at ports or intermodal rail yards and intend to continue to do so would be required to submit an application for registration in the ARB administered DTR by September 30, 2009. This would provide ample time for ARB staff to process the applications and issue DTR labels before the January 1, 2010 deadline.

Trucks for which owners have demonstrated compliance with the regulation would receive a DTR compliance label. Truck owners would be required to affix the label in a location specifically spelled out in the regulation. The label would be used by ports, terminals, and ARB to determine compliance with the regulatory requirements. Beginning January 1, 2010, drayage trucks that service ports and intermodal rail yards that do not have DTR compliance label would be deemed non-compliant and subject to potential enforcement action.

Additionally, the ARB staff envisions that the registry, being statewide, will eventually become an invaluable resource to motor carriers in determining the compliance status of drayage trucks.

C. Compliance Extensions

The only compliance extension allowed by the proposed regulation would be for model year 1994 – 2003 engines, for which no level 3 diesel particulate filters have been verified by ARB by the 2009 compliance deadline. This extension would only apply to the Phase 1 compliance deadline requiring the installation of a level 3 VDECS on 1994 – 2003 engines. Truck owners would be responsible for applying for the one-time, one-year compliance extension from ARB by June 1, 2009. If granted by the ARB Executive Officer, the compliance deadline for the truck would be extended to December 31, 2010. This extension is designed to allow for the development of new technology needed to reduce PM emissions for that particular model year engine. However, the extension is only granted for one year and cannot be renewed. After expiration of the compliance extension and no device has been verified, the truck owner would need to cease using the existing truck at ports and rail yards.

D. Exemptions

The proposed regulation would not apply to uni-body dedicated use vehicles such as dedicated auto transports, fuel delivery vehicles, concrete mixers etc. These uni-body vehicles are exempt from the proposed regulation because they represent less than five percent of the drayage truck population and differ from 'typical' drayage trucks in other aspects such as high replacement costs. Staff expects these trucks would be subject to the private fleet rule currently under development by the ARB. The proposed drayage truck rule would also not affect emergency vehicles or military tactical or combat support vehicles.

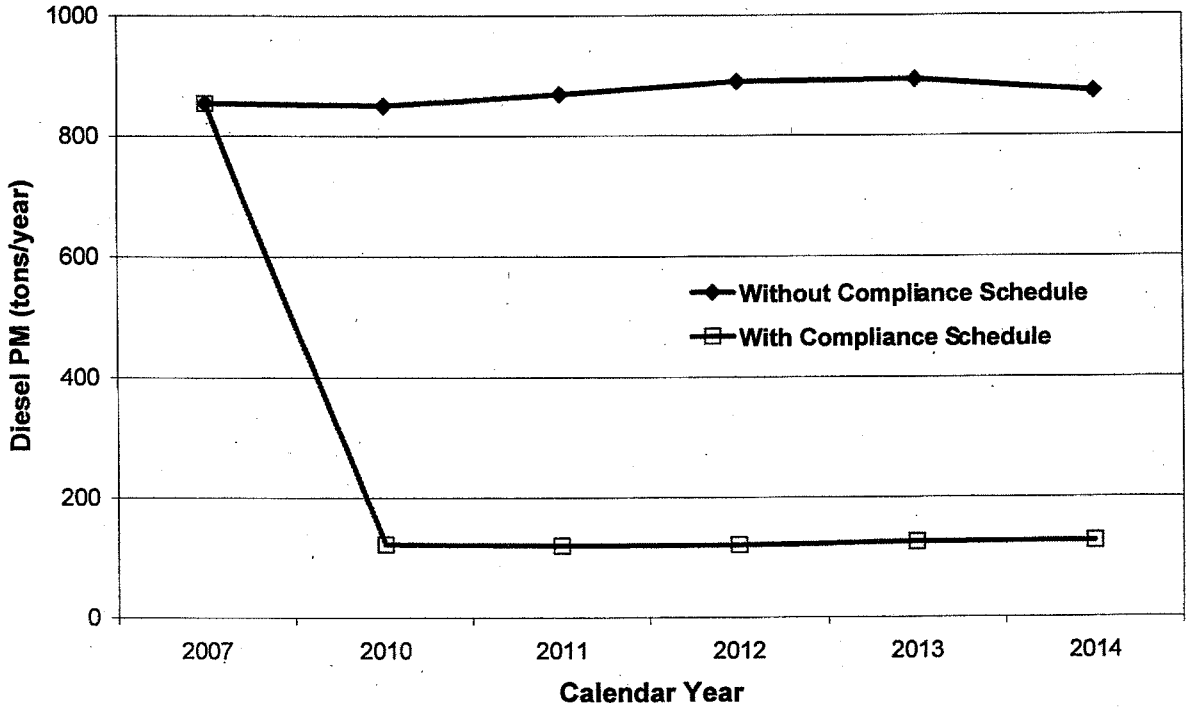
Staff realizes it is critically important to guarantee an uninterrupted flow of goods through the ports and rail yards. To that end, the regulation would also grant the ARB Executive Officer the ability to authorize non-compliant vehicles into the ports and rail yards during instances such as natural disasters.

The proposed regulation provides a process for seeking an exemption for ports or rail yards in whole or in part providing certain criteria are met. All ports and rail yards are unique, with an eclectic array of land uses – many not drayage related. As the regulation applies to truck activities on all properties owned or managed by a port or rail authority, the proposed regulation could negatively impact properties that have no drayage truck traffic or interests. An example could be the financial outlays necessary (infrastructure and staffing) to monitor all truck traffic even though the trucks are exempted under the proposed regulation. As such, the proposed regulation would allow the Executive Officer to exempt ports where the overwhelming majority of drayage trucks are exempted under the rule (i.e. ports solely serviced by dedicated uni-body car carriers). The regulation would provide a mechanism with guidelines for port or rail authorities to apply for the annual exemption if desired.

5. EMISSION REDUCTIONS

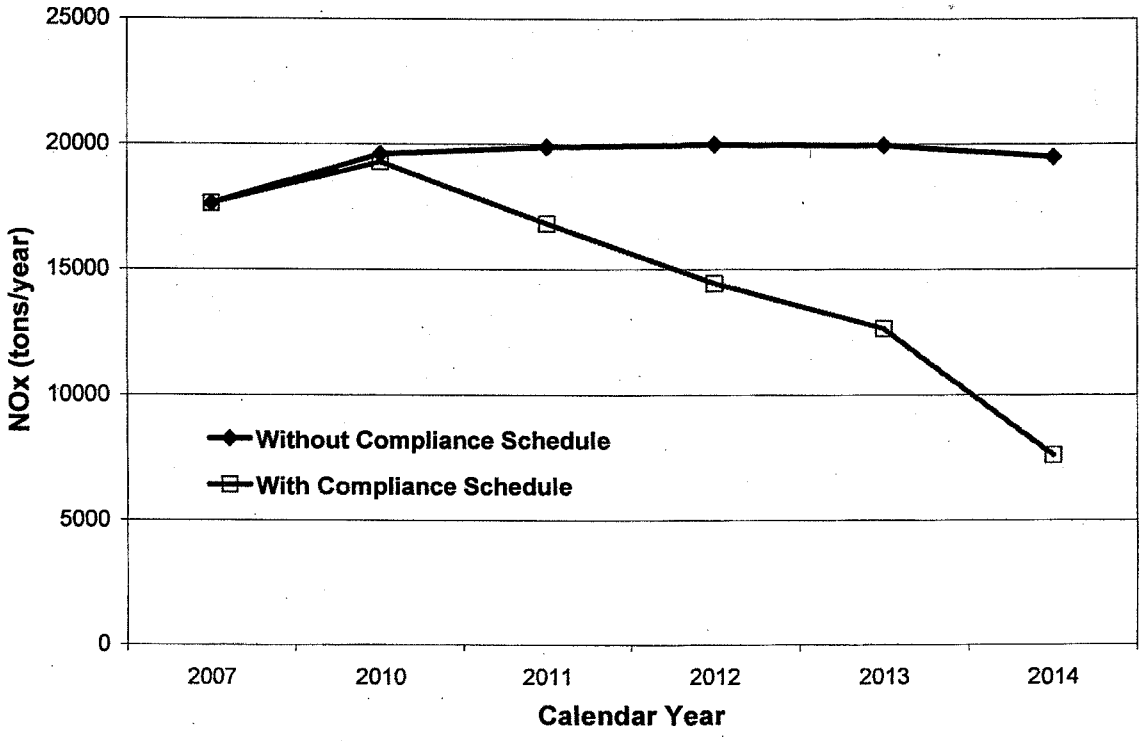
The ARB staff has estimated that the proposed regulation would substantially reduce PM and NOx emissions from drayage trucks operating at ports and intermodal rail yards and would achieve the necessary reductions to meet the Goods Movement Action Plan goals for drayage trucks. Staff has also determined that the emission reductions that would occur in both the South Coast and San Joaquin air basins from the proposed regulation would be a critical element in meeting their SIP commitments. As shown in Figures 2 and 3, in 2009, after full implementation of Phase 1, the statewide diesel PM emissions from drayage trucks would be reduced from the 2007 baseline by nearly 750 tons per year (tpy); after full implementation of Phase 2, NOx emissions would be reduced from the 2007 baseline by approximately 11,900 tpy.

Figure 2: Projected Diesel PM Emissions With and Without the Proposed Regulation



By December 31, 2013 all drayage truck engines would meet or exceed 2007 emission standards except for 2004 to 2006 MY engines. As a result, staff redistributed the population of pre-2004 MY trucks to trucks meeting 2007 or better emission standards across each of the calendar years 2010 to 2014. The result of this methodology shows a decrease in NOx emissions (Figure 3) in the years 2011 to 2013 although the proposed regulation does not require it.

Figure 3: Projected NOx Emissions With and Without the Proposed Regulation



ARB staff estimates that the proposed regulation would reduce diesel PM emissions from drayage trucks by about 86 percent by 2010. Staff also estimates that NOx emissions would be reduced by about 3 percent by 2010 and nearly 56 percent by 2014 from 2007 levels.

Although both PM and NOx uncontrolled emissions are projected to drop through the natural introduction of newer model year used diesel engines meeting the 2007 and 2010 model year emission standards into the drayage truck fleet overtime, the proposed regulation would accelerate the anticipated emission reductions. For example, without the proposed regulation, the State would not achieve the projected 2010 emission reductions of 86 percent drop in PM emissions from the 2007 baseline until 2025. The annual percentage reductions from the proposed regulation are summarized in Tables 5 and 6.

Table 5: Projected Statewide Diesel PM Benefits of the Proposed Regulation

Year	PM without Regulation (tons/day)	PM with Regulation (tons/day)	Emission Reductions from 2007 (tons/day)	% Emission Reductions from 2007
2007	3.0	3.0	0	0
2010	3.0	0.4	2.6	86
2011	3.0	0.4	2.6	86
2012	3.1	0.4	2.7	90
2013	3.1	0.4	2.7	90
2014	3.0	0.4	2.6	86

Table 6: Projected Statewide NOx Benefits of the Proposed Regulation

Year	NOx without Regulation (tons/day)	NOx with Regulation (tons/day)	Emission Reductions from 2007 (tons/day)	% Emission Reductions from 2007
2007	61	61	0	0
2010	68	67	6 (increase)*	15 (increase)*
2011	69	59	2	3
2012	70	50	11	18
2013	70	44	17	28
2014	68	27	34	56

* NOx increases are due to a growth in population of 1994-2003 MY engines from the required retirement of pre-1994 engines, increased vehicle miles traveled, and overall fleet growth.

6. ENVIRONMENTAL IMPACT

No significant adverse environmental impacts are expected to occur from adoption of, and compliance with, the proposed requirements for drayage trucks. Implementation of the proposed regulation would reduce directly emitted and secondarily formed PM levels, provide both near source and regional risk reduction, contribute to the overall effort of reducing PM mortality, hospital admissions, and lost work days, and contribute to the reduction of regional ozone formation and adverse ozone health effects through NOx emission reductions.

7. IMPACT ON GLOBAL WARMING

Overall, staff estimates that the proposed rule will reduce CO_2 emissions. CO_2 emissions from vehicles are directly proportional to fuel consumption and Phase 1 of the proposed regulation requires fleet owners to replace pre-1994 MY trucks (mechanical fuel injection) with 1994 or newer trucks (electronic fuel injection). Trucks with electronic fuel injection achieve better fuel economy (4.5 miles per gallon for mechanical fuel injection versus 6.0 miles per gallon for electronic fuel injection) and as a result,

staff estimates a diesel fuel savings of 11 million gallons per year. This fuel savings is expected to reduce carbon dioxide emissions by approximately 7 percent.

Some actions required by the proposed regulation could result in slightly increased CO_2 emissions for some applications. For example, drayage truck owners could choose to install an emission control technology (aftertreatment) to comply with the PM emission reduction requirements. An increase in CO_2 could occur if after-treatment devices, such as PM particulate filters, decrease the vehicle's fuel efficiency or increases the vehicle's weight. However, other actions required by the rule will likely offset this effect. For instance, the accelerated phase-in of newer engines, which employ modern, less polluting technologies, should reduce greenhouse gas emissions from each new engine relative to the older, in-use engines. In addition, the proposed regulation will reduce emissions of black carbon (a component of diesel PM and a likely contributor to global warming), which will further offset the minor increases in CO_2 emissions that may occur as a result of some retrofit applications.

8. ECONOMIC IMPACTS

Regulatory costs are the estimated costs resulting from the proposed regulation due to early engine (truck) replacements, emission retrofit installations, recordkeeping and reporting requirements, and enforcement efforts. The costs considered for early truck replacement includes the residual value (if applicable) of the truck being replaced, and the time value of money. These costs are those directly attributable to compliance with the proposed regulation. New equipment costs are the estimated total out-of-pocket costs for purchasing, installing, and maintenance of a newer truck or after-treatment technology, and recordkeeping and reporting. Staff estimates that the overall regulatory costs to business for complying with the proposed regulation would be approximately $1.1 - $1.5 billion (2006 dollars). Staff has estimated initial Phase 1 per vehicle costs of $10,000 - $31,000 (2006 dollars) for retrofit and/or replacement and initial Phase 2 net costs of approximately $33,000 (2006 dollars) for truck replacement, which could create an economic hardship and is further analyzed in the TSD.

ARB staff assessed the overall impact of the proposed regulation on California's economy. Staff used E-DRAM, a model of the California economy, developed by the University of California, Berkeley, to estimate the potential impacts to gross state output, personal income and employment. ARB has used E-DRAM to assess the economic impacts of several major regulations. The Department of Finance has used it in the past for policy and revenue analysis. The model is updated as industrial data becomes available and the current version is based on the latest 2003 industrial data.

E-DRAM represents the economic conditions in California in the year 2003.[3] In order to estimate future year impacts, it is necessary to produce a representation of the 2013 California economy. The 2003 data are extrapolated to 2013 based on forecasts of state population, personal income, and industry-specific growth obtained from the California Department of Finance and the UCLA Anderson School of Business.

[3] E-DRAM uses industrial data from the 2002 Bureau of Economic Analysis, Survey of Current Business.

Regulatory changes are then introduced into the model and impacts are measured as the difference between the 2013 representation with and without the proposed regulation.

The E-DRAM estimates that gross state output, personal income, and employment will grow by $530 billion (22 percent), $310 billion (23 percent), and 1.5 million (10 percent), respectively between 2006 and 2013. The implementation of the proposed rules would result in the state economy growing at a slightly slower rate. The results of analysis indicate the gross state output would be reduced by $650 - $870 million (less than 0.03 percent) and personal income would be reduced by roughly $220 million (less than 0.02 percent) in 2013. California employment growth would be reduced 2,400 to 3,300 (less than 0.02 percent) in 2013. Therefore, the impacts of the proposed regulation are small compared to the growth that is expected to occur in California over the next 7 years.

In addition, staff estimated the potential small business impacts by comparing gross margins before and after the proposed regulation and comparing it to the California per capita income level. On average, drayage truck operator gross income would be below the California per capita income level by 4 percent (Phase 1) and 10 percent (Phase 2). On average, gross margins for drayage truck owners would decrease approximately $2,300 per year. However, staff expects that compliance costs to drayage truck owners would be passed through the supply chain. The total regulatory cost is expected to be approximately $9 per container. This cost represents less than a one percent increase in standard sea-born container shipping rates. This pass through of regulatory costs will likely occur with a minimal financial impact to the drayage truck owner.

Staff also believes that Phase 2 of the regulation would provide truck owners the benefits associated with owning newer equipment. For example, newer vehicles tend to be more fuel efficient, require less maintenance, and have better reliability (less down time).

9. COST TO LOCAL, STATE, AND FEDERAL AGENCIES

The ARB is expected to be the primary state agency fiscally impacted by the proposed regulation. The ARB would be the primary enforcement entity and will require an additional four staff to perform compliance inspections and audits at a cost of $400,000 per year. Finally, the ARB will prepare and distribute education and outreach materials for all stakeholders regarding the proposed regulation. These total costs are estimated to be approximately $110,000 (education and outreach) and are expected to be absorbed within existing ARB budgets and resources.

Multiple local, State, and federal agencies could be impacted by the proposed regulation. To the extent that these agencies are responsible for port or rail operations, they will be responsible for collecting and collating truck entry information from the terminals and rail yards and relaying it to the ARB. ARB staff estimates costs to be minimal and should be absorbed within current budgets.

10. COST-EFFECTIVENESS

Cost-effectiveness is expressed in terms of costs in dollars per unit of emissions reduced (pounds or tons). Staff estimated the cost effectiveness by assuming all costs for complying with Phase 1 would be attributable to PM and all costs complying with Phase 2 would be attributable to NOx. The cost-effectiveness for Phase 1 is determined by dividing the net annualized regulatory costs for the years 2010 to 2013 by the pounds of diesel PM reduced in 2014. Similarly, NOx cost-effectiveness for Phase 2 is determined by dividing the net annualized regulatory costs for the years 2014 to 2027 by the total pounds of NOx reduced in 2014. All costs are in 2006 equivalent expenditure dollars. Tables 7 and 8 shows cost-effectiveness estimates for the proposed regulation for PM and NOx respectively.

Table 7: Cost-Effectiveness - All Phase 1 Costs to PM

Emissions	Average Total Annualized Cost 2010 – 2013	Total Emissions Reduced in 2014	Total PM Cost- Effectiveness
PM	$84 - $115 million	1,492,000 lbs	$57/lb - $77/lb

All values rounded

Table 8: Cost-Effectiveness - All Phase 2 Costs to NOx

Emissions	Total Annualized Cost 2014 – 2027	Total Emissions Reduced in 2014	Total NOx Cost- Effectiveness
NOx	$138 - $185 million	23,794,000 lbs	$6/lb - $8/lb

All values rounded

The total cost of Phase 1 is estimated to be $358 - $481 million with average annualized costs of $84 - $115 million over a 4 year capital recovery period. The total cost of Phase 2 is estimated to be $777 - $1,044 million with annualized costs of $138 - $185 million over a 14 year capital recovery period. Combining annual costs with annual emission reductions resulted in a Phase 1 PM costs effectiveness of $57 - $77 per pound and a Phase 2 NOx costs effectiveness of $6 - $8 per pound. The cost-effectiveness values are within the range of cost effectiveness for other diesel engine regulations adopted by the Board, as shown in Table 9.

Table 9: Diesel PM Cost-Effectiveness of the Proposal and Other Regulations / Measures (When All Costs Attributed to PM Reduction)

Regulation or Airborne Toxic Control Measure	Diesel PM Cost-Effectiveness Dollars / Pound PM
Public Fleet Rule	$160
Drayage Trucks*	**$57 - $77**
Commercial Harbor Craft	$29
Cargo Handling Equipment	$41
Solid Waste Collection Vehicle Rule	$28
Stationary Diesel Engine ATCM	$4 - $26
Transport Refrigeration Unit ATCM	$10 - $20

* Phase 1 cost only

The estimated value of the health benefits associated with the proposed regulation is substantial. Following standard U.S. EPA practice, ARB staff estimates the statewide benefits between 2010 and 2014 to be nearly $3.5 billion using a 3 percent discount rate, or $4.3 billion using a 7 percent discount rate. Nearly all of the monetized benefits result from avoiding premature death.

11. FEASIBILITY OF PROPOSED REGULATION

ARB staff believes that truck replacements and retrofits would be the most likely compliance options chosen to meet the proposed regulation's requirements. Staff estimates that Phase 1 would result in the replacement of up to 8,300 pre-1994 MY trucks and the installation of up to 31,000 PM retrofits. Model year 1994 to 2003 trucks are expected to use a combination of replacements and or retrofits. For Phase 2 of the regulation, staff anticipates the replacement of up to 32,000 trucks. Staff has met with industry representatives and is confident that there will be an adequate supply of used trucks, retrofit technologies, and installation and maintenance facilities to comply with the proposed regulation.

To evaluate the feasibility of the proposed regulation, staff conducted a phone survey of retrofit manufacturers, used truck dealerships, and retrofit installation facilities in California to determine the annual statewide capacity for drayage truck replacements and retrofit installations. Based on the survey, staff has estimated the current State's capacity at about 20,000 retrofit installations per year. In addition, staff anticipates additional capacity would be created based on increased demand.

Staff also believes that there will be an adequate supply of used 2007+ MY trucks available for the December 31, 2013 compliance deadline. Replacement trucks should be available nationwide and the regulation allows enough time for the 2007+ MY trucks to cycle in large quantities into the used truck market.

12. ALTERNATIVES CONSIDERED

The ARB staff considered alternatives to the proposed drayage truck regulation. One alternative would be to do nothing and rely on natural turnover to allow trucks meeting federal engine standards to gradually replace the existing fleet. Manufacturers and vendors of on-road heavy-duty diesel engines have been subject to California and federal emission standards for more than twenty years. As of January 1, 2007, new model year engines are subject to the 2007 California and federal emission standards. Unfortunately, under the current drayage business model, staff estimates that 2007+ standard trucks won't cycle into the drayage fleet in large numbers until approximately the 2020 time frame. This alternative would not achieve ARB's goals of near term PM reductions for the health of communities located near ports and rail yard facilities and would not achieve the PM and NOx reductions needed by the Board to achieve national ambient air quality standards and its SIP commitments.

A second alternative would be to require all covered drayage trucks to meet California and federal 2010+ model year emission standards by the end of 2013. This option would achieve and surpass PM and NOx emission reductions from the proposed regulation. However, in 2013, there will be relatively few used 2010 trucks available in the marketplace, as most trucks don't cycle into the used truck market until four or more years after their build date. The only compliance option would be a new model year truck with a price that could exceed $130,000 (2006 dollars). For this alternative, staff estimates PM cost effectiveness to be $166 to $223 per pound and NOx cost effectiveness to be $8 to $11 per pound. Even with the greater annual NOx emission reductions, the cost effectiveness of the alternative would be less than staff's current proposal and could create significant economic hardship for drayage truck owners. Consequently, staff has determined that this alternative is not feasible.

A third alternative would be to require half the drayage truck fleet to operate 2007+ model year emission standard engines and half operate LNG fueled trucks by the end of 2013. Similar to option 2, this option would achieve an additional 3 percent PM (<0.1 tpd) and 5 percent NOx (3 tpd) emission reductions from the proposed regulation. Staff expects there would not be an adequate supply of used LNG trucks due to current low production numbers. Staff estimates net costs for used 2007 model year trucks to be $33,000 and costs for new LNG fueled trucks to be $175,000. Staff estimates that this alternative would have a PM cost effectiveness of $132 to $178 per pound and a NOx cost effectiveness of $8 to $10 per pound. Additionally, significant challenges and costs would exist for the development of the required LNG fueling infrastructure for a fleet of this size (10,000+ trucks). LNG fueling infrastructure and fuel dispensing labor costs were also factored into the cost analysis for the regulatory comparison. Even with greater annual NOx emission reductions, the cost of this alternative is more than twice the cost of the proposed regulation which could create significant economic hardship for drayage truck owners. Consequently, staff has determined that this alternative is not feasible.

13. KEY ISSUES

Industry Economics

The proposed regulation potentially requires Drayage trucks to modernize twice, first in 2009 to reduce the risk from diesel PM emissions to nearby communities and then again in 2013 to meet the State's SIP commitments. Staff has analyzed the economics of the drayage industry and the truck owners / operators in particular. Questions arose about the affordability of the various compliance options, especially when taken in the context of the current business model at several ports, rate structures, and the near-term compliance deadlines.

Staff estimates that virtually all drayage truck owners / operators are classified as small businesses. Research based on surveys has shown that the mean net income (after deducting for fuel, insurance, and maintenance expenses) for drayage truck owners / operators in 2006 to be approximately $37,000 per year, which is approximately 50 percent of their gross annual income. The regulation is estimated to cost owners / operators approximately $10,000 to $31,000 for Phase 1 and a net cost of approximately $33,000 for Phase 2. Staff estimates owners / operators would incur annual costs of approximately $550 for emission control system maintenance and for recordkeeping and reporting requirements, which was included in the annualized cost estimate.

Staff crafted the proposed regulation to postpone the 2007 engine requirements as long as possible to minimize used truck prices. In addition, this will allow time for the development of new (and potentially less expensive) emission reduction technologies and give truck owners financial planning lead time. However, the timely attainment of federal standards in the San Joaquin Valley and South Coast Air Basins necessitate very substantial NOx reductions by 2014 to meet SIP obligations. Staff believes the 2013 compliance requirements are attainable and that sufficient lead-time has been provided for industry to generate a solution (e.g. drayage rate structure changes) that would enable truck owners to afford compliance.

Staff believes that supplemental funding (such as is available from Proposition 1B monies), a change in the drayage rate fee structure, or both will be critical in allowing many current truck owners to meet the requirements of the proposed regulation. In implementing the proposed regulation, it is expected that staff would work with the ports, terminal and rail yard operators, shippers, local districts, and other parties to secure funding to both accelerate compliance and ensure that the emission targets are met without an interruption in drayage service throughout the State. Staff will update the Board on progress in this regard and may consider proposing amendments to the proposed regulation for the Board's consideration if substantial problems are occurring and changes are needed to successfully implement the program.

Potential funding mechanisms include a number of federal and State programs that may be utilized by program administrators or truck owners. Funding programs include: The

Congestion Mitigation and Air Quality Improvement Program (U.S. Department of Transportation) which provides funding to state and local governments to support transportation projects as well as programs to improve air quality and reduce traffic congestion; The U.S. EPA's National Clean Diesel Campaign (NCDC) which offers funding and technical assistance to foster the adoption of cleaner diesel technologies and strategies; The Carl Moyer grant program that is implemented by a partnership between the ARB and local air districts; and Proposition 1B which will fund projects that reduce air pollution and consequently the resulting health risk associated with freight movement along California's trade corridors. An expanded discussion of these programs is provided in the TSD.

14. OUTREACH

ARB has worked extensively with the various stakeholders over the past two years to identify issues, find ways to address these issues, and develop appropriate regulatory language. Staff has also worked closely with the ports of Los Angeles, Long Beach, and Oakland to ensure the proposed regulation supports the emission reduction goals of the Clean Air Action Plan and the Comprehensive Truck Management Plan. The proposed regulation has been discussed with the California Air Pollution Control Officers Association (CAPCOA) during several joint CAPCOA-ARB conference calls. Additionally, ARB staff made extensive contacts with industry representatives, local air districts, environmental, pollution prevention, public health advocates, and other interested parties through meetings, telephone calls, and electronic mail. Staff has held six public workshops and five community outreach meetings (some specifically geared to truck owners / operators and their concerns) to discuss the proposed regulation. Finally, staff made information available via ARB's web site (http://www.arb.ca.gov/msprog/onroad/porttruck/porttruck.htm) to further expand public outreach opportunities and reach the widest possible audience.

15. ENVIRONMENTAL JUSTICE

A public process that involves all parties affected by the proposed regulation is an important component of ARB rulemaking activities. The proposal is consistent with the ARB's environmental justice policy to reduce health risks from toxic air contaminants in all communities, including low-income and minority communities. The proposed regulation would reduce diesel PM and other emissions from drayage trucks in all areas of the State where these trucks operate. However, the vast majority of these trucks operate within the Los Angeles/Long Beach and Bay Area ports, which are surrounded by densely populated areas, including some in low-income and minority communities. Therefore, the proposal would help address environmental justice concerns by reducing emissions and health risks in the areas where drayage truck emissions have the greatest impacts.

16. IMPLEMENTATION AND ENFORCEMENT

ARB staff needs to take the following actions to efficiently and effectively implement the proposed regulation:

- develop an outreach program to inform drayage truck owners and operators, rail operators and authorities, port terminals and authorities, and motor carriers of the requirements of the proposed regulation, as well as provide information about incentive programs such as the Carl Moyer programs, the Port of Los Angeles Air Quality Mitigation Funds, and the upcoming Proposition 1B air quality mitigation funds,
- develop recordkeeping and reporting guidance,
- develop and begin operation of the Drayage Truck Registry,
- develop an enforcement action plan which includes targeted port and rail yard field inspections and the auditing of drayage activity records; and,
- provide implementation guidance and assistance as needed.

17. RECOMMENDATION

We recommend the Board approve the proposed drayage truck regulation presented in Appendix A of the staff report. The early turnover and retrofit of drayage trucks would reduce diesel PM, NOx, and other air pollutant emissions, exposure, and health risk across California, particularly in the proximity of ports and intermodal rail yards. The proposed regulation would also support the emission reduction goals of the Clean Air Action Plan from the ports of Los Angeles and Long Beach and the Comprehensive Truck Management Plan from the Port of Oakland. The ARB staff believes the proposed regulation is technologically feasible, cost-effective, and necessary to carry out the Board's responsibilities under State law and implement provisions of the Emission Reduction Plan for Ports and Goods Movement approved by the Board in April 2006.

References:

(ARB, 1998) Air Resources Board. *Proposed Identification of Diesel Exhaust as a Toxic Air Contaminant*, Appendix III, Part A, Exposure Assessment, April 1998

(ARB, 2000) California Air Resources Board, *Risk Reduction Plan to Reduce Particulate Emission from Diesel-Fueled Engines and Vehicles,* October 2000

(ARBver, 2002) Final Regulation Order, *Verification Procedure, Warrantee and in-use compliance Requirements for in-use strategies to Control Emission from Diesel Engines*"

(ARB, 2006) California Air Resources Board, *Emission Reduction Plan for Ports and Goods Movement in California*; March 2006

(ARB-POLA-POLB HRA, 2006) California Air Resources Board, *Diesel Particulate Matter Exposure Assessment Study for the ports of Los Angeles and Long Beach*, April 2006

(BTH & Cal EPA, 2007) Business Transportation and Housing Agency and California Environmental Protection Agency, *Goods Movement Action Plan* 2007

(CAAPTech, 2006) Port of Long Beach and Port of Los Angeles, Final 2006 – San Pedro Bay Ports Clean Air Action Plan, Technical Report, November, 2006

(SPB - CAAP, 2006) San Pedro Bay Clean Air Action Plan

Appendix A:
Proposed Regulation to Control Emissions from In-Use On-Road Diesel-Fueled Heavy-Duty Drayage Trucks

Proposed Regulation Order

Regulation to Control Emissions from In-Use On-Road Diesel-Fueled Heavy-Duty Drayage Trucks

Adopt section 2027 of article 3, chapter 1, division 3 title 13, California Code of Regulations to read as follows:

Section 2027 Purpose and Definitions of Control Measure

(a) ***Purpose.*** The purpose of this regulation is to reduce emissions and public exposure to diesel particulate matter (diesel PM), oxides of nitrogen (NOx), and other air contaminants by setting emission standards for in-use, heavy-duty diesel-fueled vehicles that transport cargo to and from California's ports and intermodal rail facilities.

(b) ***Applicability***

(1) This regulation applies to owners and operators of on-road diesel-fueled heavy-duty drayage trucks operated at California ports and intermodal rail yard facilities. This regulation also applies to "motor carriers," "marine or port terminals," "intermodal rail yards," and "rail yard and port authorities."

(2) This regulation does not apply to:

(A) dedicated use vehicles;

(B) vehicles operating under an ARB authorized emergency decree;

(C) authorized emergency vehicles;

(D) military tactical support vehicles;

(E) vehicles that operate at port or rail yard properties in which the ARB Executive Officer has granted an annual exemption under the provisions of subsection (f) to local port or rail yard authorities; and

(F) yard trucks.

(c) ***Definitions.*** For purposes of this section, the definitions of Health and Safety Code section 39010 through 39060 apply except to extent that such definitions may be modified by the following definitions that apply specifically to this regulation.

(1) "ARB" means the California Air Resources Board.

(2) "ARB Designees" are defined as those entities that ARB designates or contracts with to perform certain functions or provide specific services on its behalf under this regulation.

(3) "Authorized Emergency Vehicle" is as defined in Vehicle Code section 165.

(4) "Beneficial Cargo Owner" is a cargo owner, the person for whose account the ocean or rail transportation is provided, the person to whom delivery is to be made, a shippers' association, or an ocean or rail transportation intermediary that accepts responsibility for payment of all applicable charges.

(5) "Bill of Lading" is a document that states the terms of the contract between a shipper and a transportation company. It serves as a document of title of the goods shipped, a contract of carriage, and a receipt for goods.

(6) "CARB Diesel Fuel" is diesel fuel certified by ARB as meeting the fuel specification standards set forth at title 13, California Code of Regulations (CCR) section 2280 et seq.

(7) "Class I Railroad" is a freight railway based on large revenues ($250 million or more) in comparison to the revenues of Class II (which ranges from greater than $20 million but less than $250 million) and Class III (less than $20 million) railways, as defined by the Surface Transportation Board (STB).

(8) "Compliance Label" is a tag issued by ARB or its designee under the Drayage Truck Registry for heavy-duty drayage trucks operated at the ports and intermodal rail yards that meet the requirements and compliance schedules of subsection (d) of this regulation.

(9) "Dedicated Use Vehicles" are uni-body vehicles that do not have separate tractor and trailers and include but are not limited to:

(A) Dedicated auto transports;
(B) Dedicated fuel delivery vehicles;
(C) Concrete mixers;
(D) On-road Mobile Cranes

(10) "Diesel Fuel" means any fuel that is commonly or commercially known, sold, or represented by the supplier as diesel fuel, including any mixture or primarily liquid hydrocarbons (HC) – organic compounds consisting exclusively of the elements carbon and hydrogen – that is sold or represented by the supplier as suitable for use in an internal combustion, compression – ignition (CI) engine.

(11) "Diesel-Fueled" means a CI engine fueled by diesel fuel, CARB diesel fuel, or jet fuel, in whole or part, including liquid natural gas (LNG) engines using diesel-fuel for pilot injection are subject to the requirements of this regulation.

(12) "Diesel particulate matter (diesel PM)" means the particles found in the exhaust of diesel-fueled compression ignition engines. Diesel PM may agglomerate and adsorb other species to form structures of complex physical and chemical properties. ARB has identified diesel PM as a toxic air contaminant.

(13) "Drayage Truck" means any in-use on-road vehicle with a gross vehicle weight rating (GVWR) of 33,000 pounds or greater operating on or transgressing through port or intermodal rail yard property for the purpose of loading, unloading or transporting cargo, such as containerized, bulk or break-bulk goods.

(14) "Drayage Truck Owner" means:

(A) the person registered as the owner of a drayage truck as shown by the Department of Motor Vehicles, or its equivalent in another state, province, or country; or the International Registration Plan.

or

(B) the lessee of the truck, as indicated on the drayage truck's registration pursuant to Vehicle Code section 4453.5.

(15) "Drayage Truck Operator" means the driver of the vehicle or any person, party or entity that controls operation of a drayage truck at a port or intermodal rail yard facility.

(16) "Drayage Truck Registry (DTR)" is an ARB database that contains information on all trucks that conduct business at California ports and intermodal rail yards.

(17) "Drayage Truck Registry Number" is a unique identifier issued to the owner of a drayage truck upon registering in the DTR and corresponds to the truck registered.

(18) "Emergency Event" means any situation arising from sudden and reasonably unforeseen natural disaster such as earthquake, flood, fire, or other acts of God, or other unforeseen events beyond the control drayage truck owners and operators that threatens public health and safety or the reasonable flow of goods movement.

(19) "Emergency Decree" means a determination by the Executive Officer that an emergency event has occurred that requires the immediate temporary operation of drayage trucks at ports and rail yard facilities.

(20) "Executive Officer" is the Executive Officer of ARB or his/her authorized representative.

(21) "Gross Vehicle Weight Rating (GVWR)" is as defined in Vehicle Code Section 350.

(22) "Heavy-Duty" is a manufacturer's gross vehicle weight rating of greater than 33,000 or more pounds.

(23) "Intermodal Rail Yard" is any rail facility within 80 miles of a port where cargo is transferred from truck to train or vise versa. Intermodal rail yards include, but are not limited to, the following facilities: Union Pacific (UP) Oakland, Burlington Northern Santa Fe (BNSF) Hobart, LATC Union Pacific, Commerce UP, Richmond BNSF, Commerce Eastern BNSF, ICTF UP, San Bernardino, Stockton Intermodal BNSF, Lathrop Intermodal UP, and BNSF Oakland.

(24) "International Registration Plan" is a registration reciprocity agreement among states of the United States and provinces of Canada providing for payment of license fees on the basis of total distance operated in all jurisdictions.

(25) "Lessee" has the same meaning as in Vehicle Code section 371.

(26) "Liquid Natural Gas (LNG) Fueled Trucks" are drayage trucks that utilize a heavy-duty pilot ignition engine that is designed to operate using an alternative fuel, except that diesel fuel is used for pilot ignition at an average ratio of no more than one part diesel fuel to ten parts total fuel on any energy equivalent basis. An engine that can operate or idle solely on diesel fuel at any time does not meet this definition.

(27) "Marine or Port Terminals" means wharves, bulkheads, quays, piers, docks and other berthing locations and adjacent storage or adjacent areas and structures associated with the primary movement of cargo or materials from vessel to shore or shore to vessel including structures which are devoted to receiving, handling, holding, consolidating and loading or delivery of waterborne shipments or passengers, including areas devoted to the maintenance of the terminal or equipment. For the purposes of this regulation, the term includes but is not limited to production or manufacturing areas, warehouses, storage facilities, and private or public businesses or entities located on or surrounded by port property.

(28) "Military Tactical Support Vehicles" is as defined in title 13, CCR, section 1905.

(29) "Motor Carrier" is a business intermediary that contracts with beneficial cargo owners, ship companies, port terminals or Class I railroads for pick-up and delivery of goods and with drayage truck owners, who it dispatches to ports and/or intermodal rail yards to pick up and deliver such goods.

(30) "On-road" means a vehicle that is designed to be driven on public highways and roadways and that is registered or is capable of being registered by the California Department of Motor Vehicles (DMV) under Vehicle Code sections 4000 et seq. – or DMV's equivalent in another state, province, or country; or the International Registration Plan. A vehicle covered under ARB's In-Use Off-Road Regulation, title 13, CCR, section 2449 is not an on-road vehicle.

(31) "Oxides of nitrogen (NOx)" means compounds of nitric oxide, nitrogen dioxide, and other oxides of nitrogen. Nitrogen oxides are typically created during combustion processes and are major contributors to smog formation and acid deposition.

(32) "Port" is any facility used for water-borne commerce which typically consists of different terminals, where cargo is loaded onto and unloaded from ocean-going vessels. For the purposes of this regulation, ports include, but are not limited to, the Port of Long Beach, Port of Los Angeles, Port of Humboldt Bay, Port of San Diego, Port of Hueneme, Port of Oakland, Port of San Francisco, Port of Sacramento, Port of Stockton, Port of Redwood City, Port of Crockett, Port of Richmond, Port of Pittsburg, and the Port of Benicia.

(33) "Port Authority" means those entities, either public or private, that are responsible for the operation of the ports.

(34) "Port Property" means the property constituting the physical boundaries, either contiguous or non-contiguous, of a port. For the purposes of this regulation, port property also includes privately owned property located within port boundaries.

(35) "Rail Yard Authority" means those entities, either public or private, that are responsible for the operation of Class I rail yards.

(36) "Rail Yard Property" means the property constituting the physical boundaries of intermodal rail yards. For the purposes of this regulation, rail yard property also includes privately owned property located within rail yard boundaries.

(37) "Uni-Body Vehicles" are vehicles that do not have separate tractor and trailer and include but are not limited to:

(A) concrete mixers;

(B) on-road mobile cranes;

(C) on-road construction equipment.

(38) "Vehicle" is as defined in Vehicle Code Section 670.

(39) "Verified Diesel Emission Control Strategy (VDECS)" is an emission control strategy that has been verified pursuant to the "Verification Procedure, Warranty and In-Use Compliance Requirements for In-Use Strategies to Control Emissions from Diesel Engines" in Title 13, California Code of Regulations, commencing with section 2700, and incorporated by reference.

(40) "Yard Truck" means an off-road mobile utility vehicle used to carry cargo containers with or without chassis; also know as utility tractor rig (UTR), yard tractor, yard goat, yard hustler, or prime mover.

(d) ***Requirements and Compliance*** **Deadlines.** Drayage trucks subject to this regulation must meet the following requirements by the compliance deadlines detailed in both Phase 1 AND Phase 2.

(1) ***Phase 1***: By December 31, 2009, all drayage trucks must be equipped with a:

(A) 1994 – 2003 model year engine certified to California or federal emission standards and a level 3 VDECS for PM emissions;

or,

(B) 2004 or newer model year engine certified to California or federal emission standards.

(2) ***Phase 2***: By December 31, 2013, all drayage trucks must be equipped with an engine that:

(A) meets or exceeds 2007 model year California or federal heavy-duty diesel-fueled on-road emission standards;
or,

(B) is certified to 2004 or newer model year California or federal emission standards.

(3) *Drayage Truck Owner requirements*

(A) Drayage truck owners shall:

1. meet all applicable requirements and deadlines set forth in Phases 1 and 2 above;

2. register with the DTR, according to subsection (e);

3. upon receipt of ARB issued DTR compliance label, affix label as required under subsection (e)(5);

4. ensure that all emission control devices are functioning properly;

5. maintain all installed VDECS per manufacturer's specifications;

6. maintain and keep VDECS maintenance log in the drayage truck and available upon request;

7. ensure that the drayage truck(s) has all information required under subsection (d)(5)(A)(4) for the dispatching motor carrier available and accessible in the vehicle and that the driver of the vehicle be instructed to provide the information upon demand to any enforcement personnel listed in subsection (i).

(B) Phase 1 compliance deadline extension:

1. Drayage truck owners may apply for a one-time, one-year, per-truck Phase 1 compliance deadline extension. The compliance deadline application must be either electronically filed or postmarked by June 1, 2009. To receive the Phase 1 compliance deadline extension, a drayage truck owner must demonstrate all of the following:

i. the engine installed on his/her current truck is a California or federally certified 1994 – 2003 model year engine;

ii. the truck was registered with the DTR prior to June 1, 2009;

iii. no Level 3 diesel emission control technology verified by ARB for use on that combination of truck and engine was available at the time the extension was filed.

2. Compliance extension applications shall be submitted to ARB at:

California Air Resources Board
c/o Drayage Truck Phase1 Extension
P.O. Box 2815
Sacramento, CA, 95812

or electronically through ARB's drayage truck website;

http://www.arb.ca.gov/drayagetruck

3. If after the one-year extension ARB verified technology is still unavailable, the truck owner must comply with the regulation within 90 days of the expiration of the extension by replacing the existing heavy duty truck and / or engine with a truck or engine that meets or exceeds the Phase 1 requirements .

(4) *Drayage Truck Operator Requirements*

Drayage truck operators shall, upon demand, provide the following information to authorized enforcement personnel as set forth in subsection (i):

(A) the dispatching motor carrier's contact information as detailed in subsection (d)(5)(A)(4);

(B) the VDECS maintenance log of the drayage truck.

(5) *Motor Carrier requirements*

(A) Each motor carrier shall:

1. provide a copy of this regulation or an ARB approved summarized version to each drayage truck owner that it contracts with for deliveries to ports and intermodal rail yards;

2. ensure that all trucks dispatched to a port or intermodal rail yard meet emission standards and compliance deadlines set forth in Phases 1 and 2 in subsection (d);

3. ensure that all drayage trucks dispatched to ports and intermodal rail yards are registered and in good standing with the Drayage Truck Registry (DTR) and are properly affixed with an ARB issued compliance label according to subsection (e);

4. ensure the motor carrier information listed below is available and accessible on each drayage truck covered by this regulation that it contracts with and that the driver of the vehicle is instructed to provide a copy of the information, upon demand, to enforcement personnel, as listed in subsection (i).

    i. the motor carrier's business name;
    ii. contact person's name;
    iii. motors carrier's street address, state, and zip code;
    iv. contact person's business phone number.

5. keep a record of all dispatched drayage trucks containing the information set forth in i through iv below for a minimum of five years from the dispatch date. Dispatch records are to be made available to enforcement personnel within 72 hours of an official written or oral request.

    i. truck dispatch date and time;
    ii. bill of lading or tracking number;
    iii. truck license plate number and issuing state;
    iv. Drayage Truck Registry number.

(6) *Marine or Port Terminals and Rail Yard Requirements*

(A) Starting January 1, 2009, marine or port terminals and rail yards shall collect the following information for each dispatching motor carrier and each drayage truck subject to this regulation that enters the facility not displaying a valid and current compliance label that does business at its facility.

1. Dispatching motor carrier:

    i. business name of dispatching motor carrier;
    ii. contact person's name;

iii. street address, state, zip code of the dispatching motor carrier;
iv. phone number of the dispatching motor carrier;
v. bill of lading or tracking number.

2. Drayage truck:

i. entry date and time;
ii. registered owner's name;
iii. driver's name;
iv. driver's license number;
v. drayage truck's license plate number and state of issuance;
vi. drayage truck's vehicle identification number (VIN).

All information collected in subsection (d)(6) shall be kept for a period of not less than five years from the truck entry date and is to be made available to enforcement personnel within 72 hours of an official written or oral request.

(B) Marine or port terminals and rail yards shall report the information collected in subsection (A) above to their respective authorities according to schedule (A) below and in a format acceptable to their respective authority.

Schedule A: Terminal Reporting Schedule

Date Truck Enters Terminal or Rail Yard	Date by which Information is to be Reported to Port or Rail Authority
January 1 – March 31	April 15
April 1 – June 30	July 15
July 1 – September 30	October 15
October 1 – December 31	January 15

(7) *Port Authorities and Rail Yard Authorities Requirements*

(A) Port and rail yard authorities shall respectively report the information collected by the port terminals and rail yards, as detailed in subsection (d)(6), to, and in a manor and format prescribed by, ARB according to Schedule B below. ARB reporting parameters are detailed on ARBs website http://www.arb.ca.gov/drayagetruck.

Schedule B: Port and Rail Yard Authority Reporting Schedule

Date by which Information is to be Reported to the California Air Resources Board
May 15
August 15
November 15
February 15

(B) Port and rail yard authorities shall ensure their respective terminals and/or rail yards abide by all Schedule A reporting deadlines.

(e) ***Drayage Truck Registry and Compliance Label Requirements***

(1) *Truck Owner Requirements*

(A) Owners of all drayage trucks doing business at a port or intermodal rail yard prior to September 30, 2009 and intending to continue operations after that date must register with the DTR database by September 30, 2009.

(B) Drayage trucks intending to begin operations at a port or intermodal rail yard after September 30, 2009 must be registered with the DTR database prior to commencing operations.

(C) Owners of all drayage trucks covered by the regulation must provide the following information to ARB or its designee by mail to the address in subsection (e)(2) or electronically through ARB's DTR website http://www.arb.ca.gov/drayagetruck. The information shall include but may not be limited to:

1. truck owner name, address, and contact information (e.g. phone number, email address, fax number);

2. engine make, model, and model year;

3. vehicle identification number (VIN);

4. vehicle license number and state of issuance;

5. compliance status, which shall include:

i. identifying whether the drayage truck has complied with the requirements of Phases 1 and 2, set forth in subsection (d) above;

ii. if so, how was compliance achieved (e.g. new compliant truck or description of the level 3 VDECS

that was used), who did the installation work, and when was it completed;

iii. if not, identifying when the drayage truck is scheduled to come into compliance under Phases 1 or 2.

(D) After filing the initial application, the drayage truck owner shall within 30 days of bringing a truck into compliance with Phase 1 or 2, update the DTR with the vehicle's compliance status information and any other changes to the vehicle's ownership, DMV registration status, or participation status in IRP.

(E) Upon receipt of a DTR compliance label from ARB or its designee, the drayage truck owner must affix the label in accordance with subsection (e)(5).

(2) *Mailing Address for Filing Initial Applications and Updates.* Drayage truck owners shall submit DTR applications and any updated information to ARB at:

California Air Resources Board
c/o Drayage Truck Registry
P.O. Box 2815
Sacramento, CA, 95812

(3) Failure to register with the DTR or submittal of false information is a violation of state law and subject to civil or criminal penalty.

(4) ARB or its designee shall issue a DTR compliance label upon verification of compliance with the requirements of this regulation. The DTR label will be number coded by year to show compliance through that year. For example: a compliant truck issued a 2013 coded label will be able to access ports and rail yards through 2013. After 2013, the truck will again have to demonstrate regulatory compliance and apply for a new compliance label.

(5) All DTR compliance labels shall be:

(A) located on or near the lower left hand corner on the outside of the driver's side door; and,

(B) affixed to the truck in clear view, correct side up, un-obstructed; and kept and maintained in a manner that retains legibility.

(f) ***Annual Port or Rail Yard Exemption***

(1) *Annual Exemption.* An annual exemption may be granted, under limited circumstances, by the ARB Executive Officer to ports or rail yards. An exemption may cover a clearly defined portion or the entirety of a port or rail yard. The Executive Officer has sole discretion in issuing an exemption, which will be issued to ports or rail yards that are able to demonstrate one or more of the following:

(A) port or rail yard land is not typically used for truck traffic and its primary function or location does not include or attract drayage trucks covered under this regulation (e.g. a shoreline animal sanctuary);

(B) the overwhelming majority of trucks accessing the port or rail yard are exempted under this regulation (e.g. a port where only dedicated auto transports are in service).

(2) *The Exemption Application*

(A) may be obtained from the ARBs' website http://www.arb.ca.gov/drayagetruck or by mail from;

California Air Resources Board
c/o Drayage Truck Port / Rail Yard Exemption App.
P.O. Box 2815
Sacramento, CA, 95812

(B) must be completed and submitted annually (via the same website or address listed above) no later than January 1 of the year prior to the exemption year (e.g. a 2009 year exemption application must be completed and submitted by January 1, 2008);

(C) will be approved or disapproved by the Executive Officer no later than July 1, of the year prior to the exemption year. The Executive Officer will then issue an exemption to be valid for the specified port or rail yard for the specified exemption year.

(g) ***Penalties.*** Any person who fails to comply with the performance requirements of this regulation, who fails to submit any information, report, or statement required by this regulation, or who knowingly submits any false statement or representation in any application, report, statement, or other document filed, maintained, or used for the purposes of compliance with this regulation may be subject to civil or criminal penalties under sections 39674, 39675, 42400, 42400.1, 42400.2, 42402,.2, and 43016 of the Health and Safety Code. In assessing penalties, the Executive Officer will consider factors, including but not

limited to the willfulness of the violation, the length of time of noncompliance, whether compliance was attempted, and the magnitude of noncompliance.

(h) ***Right of Entry.*** For the purpose of inspecting on-road vehicles covered in this regulation, and their records to determine compliance with these regulations, an agent or employee of ARB, upon presentation of proper credentials, has the right to enter any facility (with any necessary safety clearances) where on-road vehicles are located or on-road vehicle records are kept.

(i) ***Enforcement.*** Enforcement of this section may be carried out by authorized representatives of ARB, port and rail yard authorities; peace officers as defined in California Penal Code, Title 3, chapter 4.5, sections 830 et seq. and their respective law enforcement agencies; and authorized representatives of air pollution control or air quality management districts.

(j) ***Relationship to Other Law.*** Nothing in this section allows drayage trucks to operate in violation of other applicable law, including, but not limited to:

(1) California Vehicle Code;

(2) California Health and Safety Code;

(3) division 3, title 13, California Code of Regulations;

(4) any applicable ordinance, rule, or requirement as stringent as, or more stringent than, than the requirements of subsection (d) of this regulation.

(k) ***Severability.*** If any subsection, paragraph, subparagraph, sentence, clause, phrase, or portion of this regulation is, for any reason, held invalid, unconstitutional, or unenforceable by any court of competent jurisdiction, such portion shall be deemed as a separate, distinct, and independent provision, and such holding shall not affect the validity of the remaining portions of the regulation.

Authority Cited: Sections 39600, 39601, 39650, 39658, 39659, 39666, 39667, 39674, 39675, 42400, 42400.1, 42400.2, 42402.2., 42410, 43013, 43016, 43018, 43023, 43600, California Health and Safety Code.

Reference: Sections 39650, 39658, 39659, 39666, 39667, 39674, 39675, 42400, 42400.1, 42400.2, 42402,.2, 42410, 40717.9, 43013, 43016, and 43018, 43023, 43600, California Health and Safety Code.