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

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Release Date: October 19, 2007
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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

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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.

<u>Enforcement</u>. 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.).

<u>Emissions from Unspecified Purchases</u>. 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.

<u>Overview of the Process</u>. 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:

<u>California Climate Action Registry</u>. 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.

<u>Additional Reporting Requirements</u>. 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. General 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

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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

$$CO_2 \text{ Emissions (metric tonnes)} = [(Cli) \times (EF_{Cli}) + (CKD) \times (EF_{CKD})]$$

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:

$$EF_{Cli} = [(\text{CaO content} - \text{non-carbonate CaO}) \times \text{Molecular ratio of } CO_2/CaO] + [(\text{MgO Content} - \text{non-carbonate MgO}) \times \text{Molecular Ratio of } CO_2/MgO]$$

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

$$d = 1 - \frac{fCO_{2\,CKD} \times (1 - fCO_{2\,RM})}{(1 - fCO_{2\,CKD}) \times fCO_{2\,RM}}$$

Where:
$fCO_{2\,CKD}$ = weight fraction of carbonate CO_2 in the CKD
$fCO_{2\,RM}$ = 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

$$\text{CO}_2\text{ emissions} = \frac{\text{Direct CO}_2\text{ emissions from cement manufacturing}}{\begin{pmatrix}\text{Own clinker}\\ \text{consumed or}\\ \text{added to stock}\end{pmatrix} + \begin{pmatrix}\text{Own clinker}\\ \text{sold directly}\end{pmatrix} + \begin{pmatrix}\text{gypsum, limestone,}\\ \text{CKD \& clinker}\\ \text{substitutes consumed}\\ \text{for blending}\end{pmatrix} + \begin{pmatrix}\text{cement}\\ \text{substitutes}\end{pmatrix}}$$

(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

$$E_H = \frac{H / e_H}{H / e_H + P / e_P} \times \left(E_T - E_M\right)$$

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:

$$E_{VOC-0} = \sum_{1}^{n} CC_i * RF_{i0}$$

Where:

E_{VOC-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:

$$E_{VOC-L} = \sum_{1}^{n} C_{ief} * SV^{\beta}$$

Where:

E_{VOC-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:

$$E_{VOCP-10} = \sum_{1}^{n} CC_{i} * RF_{iP10}$$

Where:

$E_{VOCP-10}$ = 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:

$$E_{VOCP-100} = \sum_{1}^{n} C_{ief} * RF_{iP-100}$$

Where:

$E_{VOCP-100}$ = 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-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:

$$CH_4 = (E_{VOC-0} + E_{VOC-L} + E_{VOCP-10} + E_{VOCP-100}) * t * CF_{VOC} * 0.001$$

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 Energy 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:

$$CO_2 = \text{Fuel} * HHV_D * EF_{CO2} * 0.001$$

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:

$$CO_2 = CO_{2\text{-}A} + CO_{2\text{-}B} + CO_{2\text{-}C} + \ldots\ldots CO_{2\text{-}X}$$

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 Calculating 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:

$$Mileage = \sum_{i}^{n} Fuel_i * (FE_{city,i} * DP_{city,i} + FE_{highway,i} * DP_{highway,i})$$

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

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ARB COMPENDIUM OF EMISSION FACTORS AND METHODS TO SUPPORT MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

October 2007

CONTENTS

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 $\geq$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 Factors 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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REGULATION TABLE OF CONTENTS

(Not Part of Regulation – For Assistance Only)

REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

Article 1. Mandatory Greenhouse Gas Emissions Reporting

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

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(continued)

REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

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

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REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

Subarticle 3. Calculation Methods Applicable to Multiple Types of Facilities

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(continued)

REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

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Subarticle 4. Requirements for Verification of Greenhouse Gas Emissions Data Reports and Requirements Applicable to Emissions Data Verifiers

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)	
CH_4 From Oil-Water Separators				95113(c)(2)	95113(c)(2)	
CH_4 From Storage Tanks				95113(c)(3)	95113(c)(3)	
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)
Additional Methods						
Attributing Emissions to Either Thermal or Electrical Energy Production			95112(c)			
Cement Plant Efficiency Metric	95110(e)					

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