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STATE OF CALIFORNIA

California Environmental Protection Agency

AIR RESOURCES BOARD

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING

REVISIONS TO THE

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 28, 2010

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

<u>Air Resources Board Meeting</u>
December 16, 2010 at 9:00 a.m.
Air Resources Board
Cal/EPA Headquarters
Sher Auditorium
1001 I Street
Sacramento, CA 95814

This item will be considered at a two-day meeting of the Board, which will commence at 9:00 a.m. on December 16, 2010, and may continue to 9:00 a.m., December 17, 2010. Please consult the agenda for the meeting, which will be available at least ten days before December 16, 2010, 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 16, 2010, at http://www.calepa.ca.gov/broadcast

This report and related materials are available for download from the Air Resources Board's Internet site at: http://www.arb.ca.gov/regact/2010/ghg2010/ghg2010.htm. In addition, written copies may be obtained from the Board's Public Information Office, 1001 I Street, 1st Floor, Environmental Services Center, Sacramento, California 95814, (916) 322-2990.

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Climate Change Reporting Section
Climate Change Verification & Protocols Section

Reviewed by
Office of Legal Affairs
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Acknowledgments

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EXECUTIVE SUMMARY

This report presents proposed revisions to the California Regulation for the Mandatory Reporting of Greenhouse Gas Emissions. The regulation was originally developed pursuant to the California Global Warming Solutions Act of 2006 (the Act), and adopted by the Air Resources Board (ARB) in December 2007. The proposed revision to the regulation is necessary to support a California greenhouse gas (GHG) cap-and-trade program and to harmonize with the U.S. Environmental Protection Agency (U.S. EPA) federal mandatory GHG reporting requirements contained in 40 Code of Federal Regulations (CFR) Part 98. The revisions are also necessary, and authorized, to "prepare, adopt, and update" California's inventory of emissions related to climate change formerly conducted by the State Energy and Natural Resources Conservation and Development Commission pursuant to Chapter 8.5 (commencing with Section 25730) of Division 15 of the Public Resources Code. (California Health & Safety Code sections 39600, 39601, 39607, 39607.4, and 41511).

Objectives of the Proposed Regulation and Revisions

ARB staff has developed the proposed revisions to meet the requirements of the Act, the statutes listed above, and to:

- collect data that are sufficiently rigorous and consistent to support GHG cap-and-trade and other ARB programs;
- harmonize California reporting requirements with U.S. EPA reporting requirements to simplify and streamline GHG reporting;
- provide consistency with Western Climate Initiative reporting requirements while addressing specific California needs under AB 32 and other state law;
- provide for third-party verification of reported emissions data consistent with international standards.

The proposed revisions are strongly based on the U.S. EPA greenhouse gas mandatory reporting regulation adopted in 2009 (U.S. EPA MRR). ARB staff, in an intensive collaboration with colleagues in other states and provinces participating in the Western Climate Initiative (WCI), carefully reviewed the U.S. EPA regulation and developed harmonized calculation and reporting requirements. These proposed requirements include targeted modifications and enhancements to the U.S. EPA rule that are necessary to fully support a cap-and-trade program. Key additions to the U.S. EPA baseline requirements include third-party verification, more rigorous missing data provisions, and specifying emissions calculation methods that will work in a market context by accounting for the carbon variability of fuel consumed.

Context and Approach for the Proposed Regulation

Since the adoption of California's Regulation for the Mandatory Reporting of GHG Emissions in 2007 (ARB MRR 2007), there have been three significant developments:

- ARB has moved forward with developing a market-based cap-and-trade program for reducing GHG emissions, as called for in the adopted Scoping Plan. A successful cap-and-trade program requires very accurate and complete emissions reporting, which for some sources will require increased stringency in the ARB reporting regulation.
- The U.S. EPA has adopted a nationwide mandatory greenhouse gas reporting program (USEPA MRR 2009-2010). The U.S. EPA reporting requirements differ from the current ARB reporting requirements, and were not designed to support a cap-and-trade program. This potentially creates a confusing and duplicative regulatory environment for reporting GHG emissions to California and the U.S. EPA.
- The WCI, established in 2007 by Governor Schwarzenegger and the governors and premiers of six other states and four Canadian provinces, has worked to assemble common and consistent reporting requirements out of the framework of U.S. EPA's regulation. WCI's goal has been to create a GHG emissions market within a job-creating green economy among the partner states and provinces, built on a strong foundation of reported emissions data.

These developments made it clear that the existing regulation required revisions to support cap-and-trade, align with the U.S. EPA regulation to the maximum extent feasible and consistent with the needs of a market-based control program, and provide consistency with the broad-based WCI requirements – while still complying with the AB 32 requirements under which the current regulation was developed. The revisions are also necessary to update the inventory of emissions related to climate change as required by California law.

To achieve these ends, the proposed ARB reporting regulation is substantially altered in form, though the emissions monitoring practices of many reporters will not change. Under this proposal much of the current regulation is replaced with new regulatory language that cites, and where necessary, qualifies federal reporting requirements for use in meeting California reporting requirements. The staff's overall approach has been to begin with the U.S. EPA reporting requirements as a baseline, and then provide additional stringency or specificity where needed to support cap-and-trade and other ARB program elements.

This approach streamlines reporting for those entities subject to both state and federal rules, because an emissions report that meets the proposed ARB regulation will usually also meet the U.S. EPA requirements. It reduces the time and data development needed to compile emissions reports, allowing for reduced costs and consistent GHG data across government programs. At the same time, ARB is working with U.S. EPA to develop a unified mechanism for federal and state reporting to reduce or eliminate the need for separate reporting to ARB and U.S. EPA. We hope to have this unified approach in place in time for reporting of 2011 emissions in 2012.

Overview of the Proposed Regulation

The proposed regulation requires annual emissions reporting from facilities, fuel and carbon dioxide (CO_2) suppliers, and electric power entities that together account for approximately 87 percent of the total CO_2 produced by California from industrial, commercial, and mobile sources of emissions, and similar portions of methane and nitrous oxide emissions. Overall, we estimate that approximately 750 facilities, suppliers and entities would be subject to GHG reporting under the proposed revised regulation, compared to about 600 under the current regulation. Given that various facilities, suppliers, and entities are under common ownership, staff estimates that this equates to approximately 450 businesses.

<u>Who Is Affected and Reporting Thresholds</u>.

Reporters With No Reporting Threshold. For several types of reporting facilities and suppliers, the U.S. EPA regulation and this proposed revision to California's reporting regulation require "whole-sector" reporting. This means that all facilities or suppliers within the industrial sector must report their GHG emissions. In California, this applies to cement production, lime manufacturing, nitric acid production, petroleum refineries, natural gas liquid fractionators, and carbon dioxide suppliers. These types of facilities and suppliers are likely to have emissions that exceed the thresholds below, and their reporting and verification requirements are similar to those above the 25,000 metric tons (MT) of CO_2 equivalent (CO_2e) threshold.

In addition, the ARB regulation would continue to require reporting by importers and exporters of electric power; there is no emissions threshold associated with these requirements. Other electricity retail providers would continue to report their retail sales, but would be relieved of many current reporting requirements that were in place for a possible load-based point of regulation in the electricity sector.

Reporters Over 25,000 MT of CO_2e. Under the proposed revision, the majority of facilities currently subject to reporting will still be required to report. Full reporting is required for facilities emitting at least 25,000 metric tons of CO_2e emissions per year, most of which will hold a cap-and-trade compliance obligation under ARB's cap-and-trade program. Those subject to the proposed revised regulation include electricity generating and cogeneration facilities, electric retail providers and other importers and exporters of electric power, oil refineries, hydrogen plants, cement plants, and other facilities that meet CO_2e reporting thresholds for stationary combustion and industrial processes, including producers of glass, nitric acid, iron and steel, and manufacturers of lime and pulp and paper. The addition of process emissions from these sources in California is consistent with U.S. EPA reporting requirements. The proposal would also require that these facilities provide their consumption of purchased or acquired electricity and thermal energy; this is consistent with the current ARB regulation (ARB MRR 2007) and will be used to support ARB regulatory programs.

In addition to reporting by industrial facilities, most of which report under the current regulation, the proposed revised regulation requires new reporting by fuel suppliers (suppliers of transportation fuels, suppliers of natural gas, natural gas liquids, and liquefied petroleum gas), and suppliers of carbon dioxide. Reporting by fuel suppliers would substantially increase the emissions coverage of the regulation, which is necessary to support a broad cap-and-trade program that includes these sources by 2015. Also covered by the U.S. EPA regulation, suppliers report the GHGs to be emitted from the eventual combustion or use of the products supplied. To limit reporting of transportation fuels to those resulting in emissions in California, the regulation would require reporting by position holders (fuel owners) at terminal racks and refineries, and enterers (importers) of petroleum products and biofuels outside the terminal system. GHG reporting would follow practices that are already used by these suppliers to determine fuel taxes payable to the California Board of Equalization, so the addition of GHG reporting requirements should not be too burdensome.

The proposed revised regulation also includes requirements for emissions reporting by facilities in the oil and gas exploration and production sector. These requirements are included in anticipation of finalization of the U.S. EPA proposal (known as Subpart W, USEPA 2010w) for reporting GHG emissions by the oil and gas exploration and production sector. The proposed ARB requirements are based on the U.S. EPA proposal for most source types, but for some source types in this sector (as in other sectors) additional requirements are proposed to ensure the accuracy needed to support market emissions trading. Because final U.S. EPA action may not occur prior to the release of this proposal, full proposed regulatory text is included as Subarticle 5 of the revised regulation.

Reporters Below 25,000 MT of CO_2e. Facilities and suppliers with emissions between 10,000 metric tons and 25,000 metric tons of CO_2e would be included in the mandatory reporting program, but would have abbreviated reporting requirements. These reporters would report their combustion emissions using default emission factors or any other method of their choosing from the U.S. EPA regulation (USEPA MRR 2009-2010). They would also report process emissions, although these are unlikely to occur at facilities of this size. Only some oil-and-gas production facilities and a few glass production facilities are likely to have process emissions to report.

Under the current regulation, only power plants report within this emissions range (ARB MRR 2007). Under the revised regulation, power plants would continue to report down to 10,000 MT of CO_2e, but may use a simplified calculation approach. They would also report some basic information on their power generation or cogeneration systems, such as generating capacity and the amount of power generated.

Reporters in this range would also report process information associated with their emissions, such as fuel use. This will enable ARB staff to check the emissions calculation as part of their review of these reports. As part of the streamlined approach for reporters in this range, they would not be subject to other regulatory requirements for third-party verification, missing data substitution, or calibration and measurement accuracy. This will minimize costs while providing ARB a means of monitoring what is happening “below the cap” for the cap-and-trade program. This feature of the regulation is part of the WCI design recommendation.

Reporters No Longer Affected. The current ARB reporting regulation requires reporting by power plants and cogeneration facilities emitting between 2,500 and 10,000 metric tons of CO_2e (ARB MRR 2007). These facilities will no longer be subject to reporting requirements. No facility or supplier below 10,000 MT of CO_2e will be required to report to California, except in the unlikely case one is brought in by U.S. EPA whole-sector requirements.

Gases and Processes Included. The proposed revised regulation provides specific reporting requirements for each industrial sector, defining which facility processes and GHGs must be reported. In general, all facilities would be required to report their on-site stationary source combustion emissions of CO_2, N_2O (nitrous oxide), and CH_4 (methane). Some industrial sectors, such as cement, glass production, nitric acid production, and refineries, would also report their process emissions, which occur from chemical or other non-combustion activities. Some facilities would also report fugitive emissions as specified in the proposed regulation. The CO_2 emissions from biomass-derived fuels would be counted toward reporting thresholds, but separately identified during reporting to facilitate their exclusion (in most cases) from a cap-and-trade compliance obligation.

Like the current regulation, the proposal would require that those reporting their direct emissions also provide their consumption of purchased or acquired electricity and thermal energy, which facilitates emissions footprinting and supports ARB energy efficiency regulations. However, current requirements for electricity sector reporting of sulfur hexafluoride (SF_6) and hydrofluorocarbons (HFCs) have been dropped; these compounds are not subject to cap-and-trade and other ARB programs now address them more comprehensively.

Reporting Schedule and Phase-in. The data specified in the proposed revised regulation would be reported to ARB annually. The first emissions reports, for 2011 emissions, would be submitted in 2012. Most reports would be due April 1 of each year. Electric power entities and the lower-emitting facilities and suppliers eligible for abbreviated reporting would report by June 1 of each year. When reporting on 2011 emissions in 2012, facilities and suppliers could report under U.S. EPA reporting requirements if any additional monitoring equipment needed to comply with the revised ARB regulation was not in place in 2011.

Missing Data Provisions. The proposed revised regulation includes requirements for the replacement of emissions and fuel monitoring data. Because the U.S. EPA regulation was not designed for a cap-and-trade program, these additional elements are intended to prevent abuse of monitoring practices that would undermine fairness in a market program. They are based on similar requirements developed for U.S. EPA market programs, particularly the Acid Rain Program.

Third-party Verification. Most facilities and entities subject to the proposed revised regulation would be required to contract for third-party verification of their submitted emissions data reports to ensure the completeness and accuracy of the data, and to confirm the use of required methods in preparing the emission estimates. Verification would not be required for facilities emitting between 10,000 and 25,000 metric tons of CO_2e that are submitting an abbreviated report. The third-party verifiers, working in teams under the auspices of verification bodies, 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.

Verification would be performed annually, with more comprehensive reviews, including site visits, at least once during a three-year compliance period under the cap-and-trade market program. The April 1 reporters would complete verification by September 1 and the June 1 reporters by October 1. Verifier accreditation requirements are not significantly changed from current requirements (most facilities and entities affected by the proposed revised regulation are already subject to third-party verification), but the application of verification services will shift slightly as small power plants drop out of reporting and fuel suppliers come in. The revised regulation also provides for a “qualified positive” verification statement, for reports without material misstatement that have minor nonconformances with the regulation. The revised regulation also strengthens verification requirements for biomass-based fuels.

Additional Items. Other items included in the proposed revised regulation and discussed in this staff report are the detailed quantification and reporting requirements for each industrial sector, and additional detail on proposed requirements for missing data substitution, elements of verification services, verifier accreditation, data confidentiality, and document retention and record-keeping. Table ES-1 below provides a summary of the key requirements proposed, and Section I of this report provides additional background and summary information. More complete descriptions of the proposed regulation’s requirements, and issues related to its development, are found in the succeeding sections of this report.

Table ES-1
Summary of Proposed Revised Mandatory GHG Reporting Requirements

Topic/Sector		***ARB Staff Proposal***
Who Reports, What Level, How Often		♦ Facility-level reporting for identified sectors and facilities emitting ≥10,000 metric tons of CO_2e. ♦ No thresholds for refineries, Part 75 electricity generating units, cement, lime, nitric acid, or CO_2 suppliers. ♦ Reporting by fuel and CO_2 suppliers for first time. ♦ Electric power entities, including retail providers, marketers, WAPA, BPA, and DWR, report electricity imports, exports, retail sales, and pump loads, as applicable. ♦ Annual reporting of emissions and data by calendar year, beginning in 2012 on 2011 emissions. ♦ Abbreviated reports for facilities under 25,000 MT CO_2e, using default emission factors ♦ Excludes primary and secondary schools, backup generators, fire suppression equipment, some portable equipment.
Reporting Scope		♦ Stationary combustion emissions. ♦ Specified process and fugitive emissions. ♦ Specified fuel and process inputs; product outputs to support benchmarking for cap-and-trade. ♦ Energy usage--electricity in kWh and thermal in Btu—reported by facilities. ♦ Fuel and CO_2 suppliers report specified sales transactions. ♦ Electric power entities that report imported electricity must report associated specified and unspecified sources as well as emissions, based on ARB calculated emission factors.
General Requirements, Reporting Entities		♦ First-year phase-in allows use of U.S. EPA methods as applicable to the reporting entity in 2012 when 2011 monitoring was not in place. ♦ Measurement devices to be calibrated to $\pm$5 percent. ♦ Settle on chosen monitoring methods by 2013, with some allowance for later improvement. ♦ Designated representative for reporting, consistent with U.S. EPA. ♦ Retain data for 10 years for reporting entities in cap-and-trade. ♦ Changes to Enforcement language to clarify what may constitute a violation.
Gases Reported		♦ CO_2, CH_4 and N_2O reported under the revised regulation. ♦ Other Kyoto gases now reported through other ARB regulations.
Abbreviated Reporting: Facilities Under 25,000 MT of CO2e		♦ Apply default factors for stationary combustion. ♦ Report any process emissions (usually not applicable). ♦ Report fuel use, electricity generation information if applicable.

Topic/Sector		*ARB Staff Proposal*
Verification		♦ Required annually for sources above 25,000 MT CO_2e, and all operators in the cap-and-trade program. ♦ Required annually for electric power entities that are first deliverers in the cap-and-trade program. ♦ Required for biomass-derived fuel to avoid compliance obligations ♦ Will be provided by third-party verifiers that meet ARB accreditation criteria. ♦ Includes a conflict of interest policy. ♦ ARB would continue to play an oversight role in verifications and quality of verifiers. ♦ Consistent with Climate Action Reserve (CAR), The Climate Registry (TCR), the International Standards Organization (ISO) 14064-3, European Union (EU) practices, and proposed WCI requirements
Reporting and Verification Deadlines		♦ Facilities and suppliers report by April 1, verify by September 1. ♦ Electric power entities report by June 1, verify by October 1. ♦ Facilities eligible for abbreviated reports (under 25,000 MT of CO_2e) report by June 1 and are not required to verify.
Missing Data Substitution		♦ Operators would monitor fuel consumption at least weekly to facilitate use of data substitution methods. ♦ Units that report CO_2 emissions using CEMS must substitute missing data according to Part 75 rules for CEMS. ♦ Missing fuel characteristic data are substituted with historical data using a multi-tiered, increasingly more stringent approach. ♦ If the annual total facility-level fuel consumption can be accurately determined, the operator can choose the best available method to estimate missing fuel consumption data at unit-level. ♦ If the annual total facility-level fuel consumption cannot be accurately determined, missing fuel consumption data must be substituted using values correlated with other measured operational parameters or be based on historical data using a multi-tiered, increasingly more stringent approach. ♦ An ARB approved alternative monitoring plan can be used in the event of an unforeseeable breakdown of equipment that is expected to cause missing data rate to exceed 20%. ♦ Sources reporting using CEMS are allowed to temporarily use fuel-based calculation method under unforeseeable equipment breakdown.

Topic/Sector		*ARB Staff Proposal*
Emissions Quantification		♦ Methods based on U.S. EPA GHG reporting rule, with modifications for cap-and-trade consistent with WCI harmonization proposal. ♦ Stationary combustion methods require use of specified Tiers from U.S. EPA based on fuel type. ♦ Sector-specific methods are provided for process emissions from unique facility activities. ♦ Use U.S. EPA-specified standardized methods or other methods approved by consensus-based standards organizations. ♦ All sources can use default CH_4 and N_2O factors, but source testing is an option. ♦ Up to 3 percent of facility emissions may be calculated using *de minimis* methods, not to exceed 20,000 metric tons of $CO2_e$.
Stationary Fuel Combustion Sources		♦ Facilities report CO_2, N_2O, CH_4 emissions using methods according to fuel type. ♦ Facilities burning biomass fuels and specified standardized fuels can apply default emission factors and fuel use data to estimate emissions (Tier 1). ♦ Facilities burning pipeline-quality natural gas would use high heating values (Tier 2). ♦ For fuels with variable carbon content facilities would test for carbon or use continuous measurement systems.
Electricity Generating and Cogeneration Units		♦ For each generating unit, report basic equipment information, fuel consumption by fuel type, weighted average of carbon content or high heat value, and biogenic CO_2 emissions if not already required by the U.S. EPA GHG reporting rule. ♦ Report production, sales, and purchases of electricity and thermal energy if applicable. ♦ Geothermal facilities must calculate annual CO_2 and CH_4 emissions using source specific emission factors derived from an ARB approved measurement plan. ♦ For hydrogen fuel cell generating units, report basic equipment information, fuel/feedstock consumption by fuel type, and provider of fuel/feedstock.
Electric Power Entities		♦ Retail providers and electricity marketers (including WAPA, BPA, DWR, and multi-jurisdictional retail providers) provide information on imported electricity—electricity deliveries and associated emissions—to support determination of allowance obligations for Cap-and-Trade. ♦ Provisions to account for real emissions reductions. ♦ Exported electricity is reported by retail providers and marketers to support ARB GHG Inventory. ♦ Retail providers report retail sales to support calculation of free allowances under Cap-and-Trade; verification not necessary if information deemed not confidential. ♦ WAPA and DWR report additional information to support Scoping Plan Implementation measures and the Renewable Electricity Standard program.

Topic/Sector		*ARB Staff Proposal*
Cement Production		♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report process emissions estimated by the clinker-based method from U.S. EPA with plant-specific factors developed at specified intervals or by use of continuous measurement systems (Tier 4).
Petroleum Refineries		♦ Quantification methods are based on the U.S. EPA GHG mandatory reporting rule with WCI modifications incorporated. ♦ Facilities report stationary combustion emissions and process emissions from sources such as catalyst regeneration and coking.
Hydrogen Production		♦ Hydrogen producers report stationary combustion emissions and process emissions using U.S. EPA MRR methods with minor WCI modifications incorporated.
Glass Production		♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report process emissions estimated by the carbonate-based method from U.S. EPA using default CO_2 emission factors for carbonate-based raw materials or by use of continuous measurement systems (Tier 4). Not required by current ARB rule but required by U.S. EPA rule. ♦ Incorporated missing data provisions from U.S. EPA with modifications to support cap-and-trade. ♦ In addition to U.S. EPA requirements, report specified process inputs and production outputs to support benchmarking for cap-and-trade.
Lime Manufacturing		♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report process emissions estimated by the measured calcium and magnesium oxide content method from U.S. EPA using specified stoichiometric ratios or by use of continuous measurement systems (Tier 4). Not required by current ARB rule but required by U.S. EPA rule. ♦ Incorporated missing data procedures from U.S. EPA with modifications to support cap-and-trade.
Nitric Acid Production		♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report N_2O process emissions estimated by the U.S. EPA method using a site-specific N_2O emission factor and production data or by an approved alternative method. Not required by current ARB rule but required by U.S. EPA rule. ♦ Incorporated missing data procedures from U.S. EPA with modifications to support cap-and-trade.
Pulp and Paper Manufacturing		♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report process emissions; not required by current ARB rule but required by U.S. EPA rule. ♦ Incorporated missing data provisions from U.S. EPA with modifications to support cap-and-trade. ♦ In addition to U.S. EPA requirements, report specified data to support benchmarking for cap-and-trade.

Topic/Sector		***ARB Staff Proposal***
Iron and Steel Production		♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report process emissions; not required by current ARB rule but required by U.S. EPA rule. ♦ Incorporated missing data provisions from U.S. EPA with modifications to support cap-and-trade. ♦ In addition to U.S. EPA requirements, report specified data to support benchmarking for cap-and-trade.
Suppliers of Transportation Fuels		♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report CO_2, CH_4, CO_2 from biomass-derived fuels and CO_2e; not currently required by U.S. EPA rule ♦ Expands regulated entities to position holders and enterers to allow for accurate account of fuel combusted in California ♦ Expands regulated entities to producers of biomass-derived fuels to have accurate accounting of all transportation fuels ♦ Expands refinery reporting to include liquefied petroleum gas
Suppliers of Natural Gas and LPG		♦ Report based on methods specified in U.S. EPA Mandatory Reporting Rule. ♦ Report CO_2, CH_4, CO_2 from biomass-derived fuels and CO_2e; not currently required by U.S. EPA rule ♦ Expands regulated entities to interstate and intrastate pipelines ♦ Expands regulated entitles to consignees of liquefied petroleum gas ♦ Expands natural gas liquids fractionators reporting to include liquefied petroleum gas
Suppliers of Carbon Dioxide		♦ Suppliers of carbon dioxide report mass of CO_2 captured, extracted, imported and exported.
Oil and Natural Gas Systems		♦ Report based on methods specified in U.S. EPA Draft Reporting Rule: Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems ♦ Report process, vented and fugitive emissions not required by current ARB Rule but required by U.S.EPA draft rule.

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I. BACKGROUND AND INTRODUCTION

A. Structure of the Staff Report

This staff 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 revisions to the Regulation for the Mandatory Reporting of Greenhouse Gas (GHG) Emissions for California. The revisions to the regulation are necessary to support a California GHG cap-and-trade program and to harmonize with the U.S. Environmental Protection Agency (U.S. EPA) federal mandatory GHG reporting requirements. The staff report describes how the proposal 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, how the regulatory proposal was developed, and a general overview of the reporting requirements, including requirements for each industrial sector.
- Section II. Greenhouse Gas General Reporting Requirements – Discussion of the general revisions to the regulation, including topics and issues that emerged during regulation development. Biofuel purchases and stationary combustion provisions are covered in this section.
- Section III. Sector Specific Reporting Requirements – Information about the reporting and emission calculation requirements for stationary combustion and specific industrial sectors subject to GHG reporting and how they were developed.
- Section IV. Verification – Discussion of the proposed verification requirements including how emissions data reports are to be verified, the procedure and qualifications for becoming a verifier of emissions data reports or offset project data reports, 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 revisions to the existing GHG reporting regulation and why the alternatives are less effective than the proposed revised GHG reporting regulation.
- Section VIII. Summary and Rationale for Proposed Regulation.
- Section IX. References – Provides a list of references used for development of the staff report.
- Attachments. Attachments include the proposed ARB regulatory text, 40 CFR Part 98 rule sections incorporated by reference, 40 CFR Part 75 as incorporated

by reference, the text of the California Global Warming Solutions Act of 2006, and the federal rules related to the staff proposal.

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 is also positioning 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, Núñez, Statutes of 2006, chapter 488) (AB 32 or the Act) to exercise this leadership role. Key provisions of the Act required 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 (ARB Scoping Plan 2008) 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 GHG reduction program requires a system to estimate, report, and track GHG emissions, to aid the identification and implementation of emission reduction strategies, and to 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 required 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, ARB was charged to:

- 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;
- 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.

In December of 2007, the Board adopted the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (Subchapter 10, Article 2, sections 95100 to 95133, title 17, California Code of Regulations). Over the past two and a half years, ARB staff have successfully deployed and maintained the GHG reporting program as required by the regulation. This has included identification of facilities subject to reporting, development of a broad array of guidance materials, presentation of many training sessions for reporters and verifiers, the creation of an online GHG emissions reporting tool, establishment of a third-party verification program, and ongoing support to reporters and verifiers.

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

With California now developing a proposed GHG cap-and-trade system, and following the adoption of federal GHG emissions reporting requirements, it is necessary to update the existing California GHG reporting regulation. In addition to the authority provided by AB 32, the authority to adopt the proposed amendments is provided by other provisions of the California Health and Safety Code that are not part of AB 32. The following provisions provide ARB with separate, independent authority to adopt the proposed amendments: sections 39600, 39601, 39607, 39607.4, and 41511 of the Health and Safety Code. Section 39607 requires ARB to inventory sources of air pollution and kinds and quantities of air pollution from these sources. As part of this requirement, Health and Safety Code section 39607.4 requires ARB to "prepare, adopt, and update" the inventory of emissions related to climate change formerly conducted by the State Energy and Natural Resources Conservation and Development Commission pursuant to Chapter 8.5 (commencing with Section 25730) of Division 15 of the Public Resources Code. The amendments to the existing GHG reporting requirements are therefore also necessary to ensure an accurate, updated inventory of GHG emissions in California.

An overview of the approach for making the updates follows.

C. Development of the Regulatory Proposal

Since the adoption of ARB's current GHG reporting regulation in 2007 there have been two important developments. First, as called for in the Board-approved Scoping Plan, ARB staff has moved forward with developing a GHG cap-and-trade system as a mechanism to reduce GHG emissions. Because a GHG cap-and-trade system creates a marketable commodity out of GHG emissions, accuracy of GHG emissions estimation is critically important. ARB staff has to strengthen our current reporting rules to reduce the possibility of incomplete, inconsistent, or inaccurate reporting.

Secondly, in 2009, the U.S. EPA adopted federal requirements for mandatory GHG emissions reporting, as called for in the FY2008 Consolidated Appropriations Act (H.R.

2764; Public Law 110–161).[1] The U.S. EPA reporting requirements are similar in many respects to the existing ARB reporting requirements. In addition to numerous small differences in a rule of its size, the federal rule is broader in scope, bringing in additional industrial sectors and sources of process emissions. The broad scope serves the needs of an economy-wide cap-and-trade program, but as U.S. EPA points out, the federal regulation was not designed to fully support a cap-and-trade program. There are instances where applied methods lack sufficient rigor or would not result in a consistent and accurate emissions estimation by source type. The missing data provisions in the federal regulation are also not strong enough to support a market-based emissions trading system. Moreover, in order to effectively support a cap-and-trade program, there is also a need to retain and enhance a strong verification component for careful review of each emissions report and error correction when needed.

To meet these concerns while developing a regulation that would minimize the duplication of reporting efforts, ARB staff worked to carefully review and evaluate the U.S. EPA regulation and develop harmonized calculation and reporting requirements. Staff undertook a review of the feasibility of aligning the proposed ARB mandatory reporting regulation (ARB MRR 2007) with the new *U.S. EPA Final Rule for the Mandatory Reporting of Greenhouse Gases* (USEPA MRR 2009-2010), starting with discussions with U.S. EPA staff in late 2009. Concurrently, the WCI Reporting Committee was directed by the WCI Partners to harmonize the *WCI Essential Requirements for Mandatory Reporting* (WCI ERMR 2009), which had been developed to support a regional cap-and-trade program, with the U.S. EPA rule, which had not been developed to support cap-and-trade. ARB staff participated in extensive discussions with the other WCI jurisdictions through the WCI Reporting Committee to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. The process resulted in the *Proposed Harmonization of Essential Requirements for Mandatory Reporting* (WCI HER 2010), released by the WCI Partners on May 28, 2010.

By using the U.S. EPA reporting regulation rather than the current ARB regulation as our starting point in writing reporting requirements for cap-and-trade, ARB staff has endeavored to substantially reduce the reporting burden on California reporters by avoiding or minimizing duplicative monitoring and reporting requirements. By working collaboratively with, and sharing expertise among, the WCI jurisdictions, ARB staff was able to efficiently identify which elements of the complex U.S. EPA reporting regulation required revision to support a California and western region cap-and-trade program. The harmonized requirements, to be applied throughout the WCI region, will allow reporters to formulate and submit emissions reports that meet the needs of a cap-and-

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[1] The FY2008 Consolidated Appropriations Act mandated that at least $3,500,000 provided in the Environmental Programs and Management account would be provided a rule "to require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States. " Division F, Title II, Administrative Provisions, Environmental Protection Agency (Including Rescission of Funds) (US Congress 2008)

trade program, and in most cases, satisfy federal reporting requirements without additional work.

Public Outreach. In order to build on the public outreach conducted in the development of the existing GHG reporting regulation,[2] and to help develop the proposed revised regulation and get public feedback, a day-long workshop was held March 23, 2010 to hear from stakeholders and discuss our overall approach and sector specific requirements.[3] Staff discussed the twin goals of aligning with federal requirements and developing a reporting program to support the GHG control program, including proposed cap-and-trade rules. Staff presented current thinking on rule applicability, reporting schedules, *de minimis* emissions, measurement accuracy, missing data procedures, and other topics.[4] Longer sessions presented concepts and current thinking on third party verification, methods for stationary combustion and process emissions sources, reporting by electricity first deliverers, and reporting by fuel suppliers.[5] Extensive comments were received during and in the weeks following the workshop. Staff considered each comment carefully as regulatory language was developed through the course of the spring and summer.

In addition to the spring workshop, staff met in person and by teleconference numerous times with stakeholders. Often these meetings grew out of discussions on implementation of the current regulation as reporting entities worked to complete their second year of reporting and first year of verification. Where implementation challenges have arisen, staff has used the opportunity of the regulation revision to consider lessons learned, and applied them in this regulatory proposal. ARB staff and reporters have been working with an established regulation and have learned much through the first two years of the reporting program. Because of this experience and the mutual desire to support alignment with federal requirements -- themselves developed through a public process – stakeholders have said they prefer that the ARB and U.S. EPA rule be as consistent as possible to simplify reporting.

ARB staff also participated in the U.S. EPA training session on federal reporting held May 4, 2010, in Los Angeles. Staff discussed our effort to align the requirements of the ARB regulation with U.S. EPA's requirements when modifying the regulation to support cap-and-trade, and answered questions on the regulation and this approach. Staff also participated in stakeholder discussions organized by WCI to hear comments in

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[2] In developing the existing GHG reporting regulation, ARB staff conducted five workshops and met multiple times with individual stakeholders to discuss various aspects of GHG reporting. Staff also responded to comments submitted prior to taking the existing regulation to the Board, and during the 45-day comment period, as well as two 15-day comment periods. *See* Staff Report: Initial Statement of Reasons (ARB ISOR 2007), page 3, *see also* Final Statement of Reasons, Including Summary of Comments and Agency Responses (ARB FSOR 2008).

[3] Notice for the March 23, 2010 Workshop to Discuss Revisions to the California Mandatory Greenhouse Gas Reporting Regulation (ARB Wkshp Notice 2010)

[4] ARB Staff Workshop Slides, Workshop to Revise ARB's Mandatory Greenhouse Gas Reporting Regulation, March 23, 2010 (ARB Wkshp Slides Gen 2010)

[5] ARB Staff Workshop Slides, Combustion and Industrial Sectors (ARB Wkshp Slides Cmb 2010); Electricity Deliverers (ARB Wkshp Slides Elec 2010); and Fuel Suppliers (ARB Wkshp Slides Fuel 2010).

response to the *Proposed Harmonization of Essential Requirements for Mandatory Reporting* (WCI HER 2010).

Basic Approach. To accomplish harmonization within the confines of California rulemaking processes, the proposed regulation is somewhat unique in its approach. In order to ease confusion for reporters and to help ensure good data quality, the proposed regulation directly references the U.S. EPA requirements, telling reporters where they must comply with specific applicable sections of the federal rule to meet ARB requirements. We then stipulate any needed limitations, modifications, or additions to the federal requirements where necessary to support California's cap-and-trade program. A typical lead-in paragraph for a section is provided below as an example:

> The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with Subpart AA (40 CFR §§98.270 to 98.278) in reporting annual emissions to ARB except as otherwise provided in this section.

The remainder of the section then describes what additional ARB requirements must be met. This may include, as examples, the exclusion of an estimation method that lacks sufficient rigor, and the inclusion of requirements for what the reporter must do if key measurement data are missing.

Thus, a California reporter will essentially comply with the federal requirements, but in some cases will need to use more rigorous methods to provide data that is of cap-and-trade quality. This means most reporters will need to be familiar with the U.S. EPA regulations – and usually already will because it is a rule that affects them directly. They will then need to become familiar with any California reporting differences specified in the revised ARB regulation. By structuring our regulation such that it incorporates specific provisions of the U.S. EPA rule while concisely listing differences, we have tried to make the reporting process in California as straightforward and transparent as possible.

Note that U.S. EPA continues to modify its own regulation. ARB staff has reviewed the modifications finalized by U.S. EPA as of October 7, 2010, and included these changes in the staff proposal. Additional U.S. EPA rulemakings, and their consistency with the needs of the cap-and-trade program, will be considered later. The complete text of the U.S. EPA regulation is available at: http://www.epa.gov/climatechange/emissions/ghgrulemaking.html. (USEPA MRR 2009-2010). Table I-1 below is intended to help the reader refer to similar requirements in both regulations.

Lower-emitting Facilities. The U.S. EPA rule applies a reporting threshold of 25,000 metric tons of CO_2e to most types of facilities. The WCI design framework includes monitoring emissions below the thresholds associated with a cap-and-trade compliance obligation, which is also 25,000 MT of CO_2e. Consistent with the WCI decision, this regulatory proposal includes a reporting threshold of 10,000 metric tons of CO_2e for the facilities with a federal reporting threshold. (This is the level of emissions associated with burning about 180 million standard cubic feet of natural gas, or 1.85 million therms.) ARB staff has worked to minimize this new reporting burden for facilities beneath the cap by developing simplified reporting requirements for those facilities. This abbreviated reporting option for smaller facilities is intended to cut through the complex federal reporting rules applied to facilities emitting over 25,000 metric tons of CO_2e. The abbreviated reporting requirements are found in section 95103(a) of the regulatory proposal. Fuel sampling and testing are not required for these facilities, though they may choose to apply those options if they are close to the cap-and-trade emissions threshold. Most will choose default emission factors and report at a relatively low cost.

Table I-1. Cross-Reference Between Proposed ARB Mandatory Reporting Regulation Revision and Related U.S. EPA Reporting Requirements

Topic or Industrial Sector	***ARB MRR Section***	***40 CFR Part 98 Sections***
Purpose and Scope	95100.5	98.1
Applicability	95101	98.2
Definitions	95102	98.6
Greenhouse Gas Reporting Requirements	95103	98.3, 98.4
Greenhouse Gas Emissions Data Report	95104	98.3, 98.5
Document Retention and Record Keeping	95105	98.3 (g)
Enforcement	95107	98.8
Standardized Methods	95109	98.7
Cement Production	95110	98.80-88
Electric Power Entities	95111	n/a
Electricity Generation and Cogeneration	95112	98.30-38, 98.40-48
Petroleum Refineries	95113	98.250-258
Hydrogen Production	95114	98.160-168
Stationary Fuel Combustion Sources	95115	98.30-38
Glass Production	95116	98.140-148
Lime Manufacturing	95117	98.190-198
Nitric Acid Production	95118	98.220-228
Pulp and Paper Manufacturing	95119	98.270-278
Iron and Steel Production	95120	98.170-178
Suppliers of Transportation Fuels	95121	98.390-398
Suppliers of Natural Gas, Natural Gas Liquids, and Liquefied Petroleum Gas	95122	98.400-408
Suppliers of Carbon Dioxide	95123	98.420-428
Petroleum and Natural Gas Systems	95150-95158	Proposed 98.230-238
Substitution for Missing Data Used to Calculate Emissions from Stationary Combustion and CEMS Sources	95129	98.35
Verification of Emissions Data Reports and Verifier Accreditation	95130-95133	98.3(f)

D. Proposed Revised Regulation – A Summary

1. Objectives of the Proposed Regulatory Action

The purpose of this proposed revised regulation is to meet the requirements of AB 32 to develop a comprehensive and effective mandatory GHG reporting program for California. The revisions provide needed updates to support the ARB cap-and-trade program and other programs. It also harmonizes most California reporting requirements with the U.S. EPA reporting requirements to simplify and streamline GHG emissions reporting. Our primary objectives have included: requiring reporting for the most significant GHG emissions sources, using rigorous and consistent emission accounting methods, providing for third-party verification of reported data, and harmonizing with U.S. EPA and WCI GHG reporting requirements.

2. Overview of General Requirements

The proposed revised GHG reporting regulation includes annual emissions reporting from facilities, fuel suppliers, and electric power entities that account for approximately 87 percent of California's total CO_2e emissions from all sources. The addition of new industrial process emissions categories, new reporting by suppliers of natural gas and transportation fuels, and the reporting of emissions (not just transactions) by electricity importers all extend the emissions coverage of the regulation.

Like the federal regulation, the staff proposal requires facilities to consider their emissions from process emissions sources, in addition to combustion emissions. These industrial process sources, which occur from chemical or other non-combustion activities, include emissions from glass production, lime manufacturing, nitric acid production, pulp and paper manufacturing, and iron and steel production. Staff is also proposing process emissions reporting from petroleum and natural gas systems sources included in the U.S. EPA's proposed Subpart W rule, scheduled for inclusion in the federal reporting requirements in the Fall of 2010. These industrial process source categories are proposed as additions to those process sources included in the current ARB regulation, including cement production, power plants, petroleum refineries, and hydrogen plants.

<u>Gases and Basic Requirements</u>. The proposed regulation provides detailed reporting specifications for each industrial sector, defining which facility processes and GHGs 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). The CO_2 emissions from biomass-derived fuels would be separately identified during reporting.

The industrial sectors mentioned above would also report specified process emissions of these same gases, which occur from chemical or other non-combustion activities. Facilities report fugitive emissions when specified in the regulation.

Particular California requirements apply to the electric power sector to meet the requirements of AB 32 and the needs of the proposed cap-and-trade program. Retail providers and marketers who import or export electricity would report specified electricity transactions and calculate emissions associated with them.

All reporters would provide certain specified information including:

- California-specific information such as ARB identification number, air district, air basin, and geographic location;
- A designated reporting representative, as required by U.S. EPA;
- Specified information on the entity's corporate parent and NAICS codes, as currently proposed by U.S. EPA;
- Consumption of purchased electricity and thermal energy, and the provider of that energy. Such information is usually not difficult for reporters to compile and is important for the implementation of certain GHG control programs, including the energy audits regulation and the proposed cap-and-trade regulation.

Reporters would be required to retain records associated with their emissions reports for a period of ten years when they are associated with a cap-and-trade compliance obligation, and five years when they are not. This is to assure that any question that comes up about a past report can be resolved, particularly if it involves a compliance obligation.

Reduced Burden. The proposed regulation would also relieve the current reporting burden from certain facilities as follows:

- Power plants that emit below 10,000 metric tons of CO_2e would no longer be required to report; the current reporting threshold is 1 megawatt and 2,500 metric tons of CO_2e.
- Retail providers would no longer be asked to report a range of data that would have been needed had a load-based point of regulation been developed for the electricity sector.
- Facilities and entities would no longer be required to report sulfur hexafluoride (SF_6) and hydrofluorocarbon (HFC) emissions; other ARB regulations now cover this requirement more comprehensively and a duplicative requirement here is unwarranted.
- Fugitive emissions of CH_4 from coal storage would no longer be required in reporting by cement and power plants; these very small emissions are highly uncertain and not needed for ARB's control programs.

Reporting Responsibility. The U.S. EPA regulation refers to facility "owners and operators" or "owners or operators" as responsible for submitting the emissions report. The ARB staff proposal clarifies that where the owner and operator of a facility are not the same, the operator has the responsibility for compliance. The operator is defined as having operational control over a facility. For this proposal, as for the current ARB reporting regulation, operational control means the authority to introduce and implement operating, environmental, health and safety policies. Where such responsibilities are shared, the party holding the air quality permit is considered to have operational control.

Suppliers of fuels and industrial gases, including producers, importers, and exporters, report to U.S. EPA. Suppliers of fuels and CO_2 would also report to ARB, but some additional entities are specified as suppliers to allow products exported from California to be excluded, and other specified products to be included. The additional entities in the supplier category include position holders at terminal racks and refineries, enterers of petroleum products and biofuels, biofuel producers not already reporting to ARB, and consignees of liquefied petroleum gas. Local distribution companies, pipeline operators and natural gas fractionators would also report to ARB as fuel suppliers. Producers and importers of carbon dioxide report to ARB, but like fuel suppliers, may exclude products destined for export from California.

Importers and exporters of electricity also report to ARB. This includes California and multijurisdictional retail providers, power marketers, the Western Area Power Administration, and the California Department of Water Resources. Retail providers currently reporting electricity transactions and retail sales to ARB will only report retail sales, if they are not importing or exporting power.

Electricity generating facilities that are solely powered by nuclear, hydroelectric, wind or solar energy electricity generating sources would not be required to report under the proposed revised regulation, unless they have sufficient stationary combustion onsite to meet the reporting thresholds of the regulation. Backup generators and fire suppression equipment are excluded, as is portable equipment at most types of facilities. Primary and secondary schools would still not have to report. Hospital would now be required to report when they have combustion emissions exceeding 10,000 metric tons of CO_2e; some have significant power generation onsite and offer power to the grid.

ARB staff estimates that approximately 750 emitting facilities, suppliers and entities would be subject to GHG reporting under the proposed revised regulation, compared to about 600 currently (ARB GHG Summary 2010, ARB CEIDARS 2007). Given that various facilities, suppliers, and entities are under common ownership, staff estimates that this equates to approximately 450 businesses (ARB GHG Summary 2010, ARB CEIDARS 2007).

Reporting and Verification Schedule. The proposed revised regulation, like the current one, requires facilities subject to reporting to submit an emissions data report annually to ARB. Emissions data reports would be submitted for the previous calendar year. Staff is again proposing a bifurcated reporting schedule, with April 1 and June 1 deadlines. The April 1 deadline would apply to facility operators and fuel/CO_2 suppliers. The June 1 deadline would apply to electric power entities. Operators who do not report to U.S. EPA and have no cap-and-trade compliance obligation (facilities under 25,000 metric tons of CO_2e) may also report by the June 1 deadline.

Annual third-party verification by accredited verification bodies would be required for all reports of emissions that equal or exceed 25,000 metric tons of CO_2e. Facility operators and suppliers must complete verification by September 1 of each calendar year, and electric power entities by October 1.

Phase-in Year. ARB staff proposes a one-year phase-in period to allow facilities and suppliers who have not previously reported GHGs to ARB, and are not required to report GHGs to U.S. EPA, to develop monitoring systems, train personnel in data collection, and install any necessary equipment. The first emissions data reports under the proposed revised regulation, for 2011 emissions, would be submitted in 2012. Facilities and suppliers would be permitted to report on 2011 emissions using only the requirements in the U.S. EPA regulation (USEPA MRR 2009-2010). This approach recognizes that any changes in monitoring methods necessitated by new California requirements will not be immediately effective in 2011, and provides time for facilities and suppliers to accommodate them. All future emissions reports would need to fully comply with specified calculation requirements.

Cessation of Reporting. Similar to U.S. EPA requirements, reporting entities would be entitled to cease reporting once emissions drop below specified thresholds for an extended period. The cessation thresholds are different because the reporting threshold is different: reporting may cease after five years below 10,000 metric tons of CO_2e, or three years below 5,000 metric tons CO_2e. In cases of facility shutdown or modification that eliminates GHG emissions, reporting may cease after one year of reporting zero emissions.

Non-submitted/Non-Verified Emissions Data Report. In the event a reporting entity fails to submit an emissions data report or fails to get an emissions data report verified by the applicable deadline, the Executive Officer will calculate an assigned emissions level for that reporting entity. The Executive Officer will evaluate several factors in developing that assigned emissions level. The facility number calculated by the Executive Officer becomes the reporting entity's obligation under the cap-and-trade program.

Missing Data Provisions. Many of the provisions for missing data substitution in the U.S. EPA reporting rule could potentially be subject to abuse in a cap-and-trade system. To address these concerns, the proposed rule requires the operators to follow these procedures in substituting for missing data:

For 40 CFR Part 75 units, follow 40 CFR Part 75 (revised as of July 1, 2009) missing data substitution procedure. (This is consistent with U.S. EPA reporting rule requirement). For non-Part-75 units that report CO_2 emissions using a continuous emissions monitoring system (CEMS), substitute missing data according to 40 CFR Part 75 rules for CEMS.

For missing fuel characteristic data (heat value, carbon content, moisture content, and molecular weight), apply an increasingly more conservative substitution method based on percent data capture rate. At a capture rate above 90%, use the U.S. EPA approach in Part 98. At a capture rate below 90%, substitute the missing value with the highest value recording during specified lookback periods.

For missing fuel consumption data, the operator has leeway in selecting the best available estimate method as long as the annual total facility-level fuel consumption can be accurately determined. In the rare instances where annual fuel use cannot be accurately determined, missing fuel consumption data must be filled with values that can either be correlated with other measured operational parameters or be based on the actual fuel use values under usual operating conditions. (See Section II.C for additional discussions.)

In the event of an unforeseeable breakdown of equipment that is expected to cause a missing data rate of more than 20%, operators meeting certain criteria can use an alternative monitoring plan approved by ARB. Sources reporting using CEMS are allowed to temporarily use a fuel-based calculation method if certain criteria are met.

Miss data elements cumulatively causing more than 80% of emissions to not be directly calculated from measure parameters is an automatic nonconformance, even if the operator has correctly followed all the missing data substitution procedures in the rule.

<u>Other General Provisions</u>. The proposed regulation retains, with some modifications, current requirements regarding *de minimis* emissions. U.S. EPA requirements for calibration or measurement equipment are included in the proposal, with an additional stipulation that ARB is notified about, and can approve, delays in calibration. Other items included in the proposed general requirements are definitions, specifications for claiming confidential data, and language on enforcement of the regulatory provisions. With rare exceptions, and in order to avoid inconsistent interpretations, the proposed definitions are fully consistent with definitions in the U.S. EPA regulation. Definitions have been added for the provisions of this regulatory proposal not covered by federal reporting requirements.

3. Overview of Requirements for Stationary Fuel Combustion Sources

<u>Stationary Fuel Combustion Sources</u>. This component of the regulation applies to multiple industrial sectors, and includes devices that combust solid, liquid, or gaseous fuels, generally for the purposes of generating steam, producing electricity, providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters. This is the most important single source category as it is present at almost every facility.

The proposed revised regulation specifies reporting requirements and methods to calculate CO_2, CH_4, and N_2O by fuel type. The proposal is based on the U.S. EPA's tiered series of combustion methods, with limitations applied by fuel type to ensure a high degree of accuracy. Use of the lower-tier methods is limited to pipeline quality natural gas and standardized liquid fuels. Carbon testing or use of CEMS is required for other fuels due to the likelihood of variable carbon content. Additional specifications are proposed for CEMS CO_2 monitoring.

As in the current ARB regulation, only units combusting biomass or municipal solid waste could apply the Tier 2 steam production method. The proposal would also continue the daily sampling of refinery fuel gas that is required in the current reporting regulation, and site-specific emission factors derived from source testing are again provided as an option for CH_4 and N_2O emissions.

4. Overview of Requirements for Electric Power Entities

Electric power entities are required to continue reporting imported electricity, exported electricity, and retail sales, as applicable. In the revised proposed regulation, electric power entities will now also report emissions associated with imported and exported electricity, pursuant to the methods provided. Reported emissions associated with imported electricity will inform the cap-and-trade program compliance requirement for first deliverers of electricity to hold allowances. Retail sales data are needed to inform the allocation of free allowances for retail providers. Exported electricity is reported for ARB inventory purposes. ARB is continuing to require retail providers to report out-of-state facility ownership share and contracts in order to evaluate whether anticipated decreases in future imported electricity emissions are due to resource shuffling or real emissions reductions in the western regional power system due to California's cap-and-trade program.

The proposed revisions include a new requirement that the Western Area Power Administration (WAPA) report pump loads for the Central Valley Project, as well as maintaining the requirement that the California Department of Water Resources (DWR) continue to report its State Water Project pump loads. These requirements will support future analysis of GHG implications of water conservation and efficiency measures. DWR and WAPA are also included as regulated entities in the proposed Renewable Electricity Standard (RES) regulation (*see* proposed title 17, *California Code of Regulations,* section 97000 et al.). ARB staff is currently assessing mechanisms to allow DWR and WAPA the option of satisfying RES reporting requirements through the mandatory GHG reporting regulation and may propose 15-day changes to the currently proposed regulation.

Two reporting requirements of the current regulation (ARB MRR 2007) have been removed: (1) out-of-state facilities are no longer required to obtain verification of their emissions data reports, and (2) reporting wholesale electricity purchases and sales from California sources for electricity that is consumed in California is no longer required.

5. Overview of Reporting Requirements for Industrial Facilities

Cement Production. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for cement production facilities. The propose ARB regulation would affect eleven California plants, which are also subject to the U.S. EPA reporting rule for greenhouse gases. All California cement plants would be required to report combined process-related and combustion CO_2 emissions from clinker production using the CEMS methodology or separately report combustion emissions and process-related CO_2 emissions. When separately reporting combustion emissions, cement plants would be required to report emissions of CO_2, biomass-derived CO_2, CH_4, and N_2O from kiln and other combustion sources by using fuel-specific methods, which may involve carbon or heat value testing. When separately reporting process-related emissions from clinker production, cement plants would be required to follow the regulation's specified clinker-based methodology and to also report process-related emissions from the organic carbon entrained in non-carbonate raw materials consumed. In addition, facilities would report quantities of fuel used, fuel characteristics, quantities of raw material consumed, annual clinker production, and other supporting data to allow ARB to calculate efficiency metrics and support benchmarking for the cap-and-trade program.

Electricity Generating and Cogeneration Units. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for electricity generation and cogeneration facilities. The proposed ARB regulation would affect approximately 150 electricity generating facilities and about 130 facilities with cogeneration units. About a third of the cogeneration units are stand-alone generating facilities and the remainder are included as part of another reporting facility. Operators of electricity generating and cogeneration units emitting 10,000 metric tons of CO_2e per year or more would be required to report emissions of CO_2, biomass-derived CO_2, CH_4, and N_2O, using methods that are specified in the proposed regulation. Facilities emitting 25,000 metric tons of CO_2e per year or more would be required to choose a calculation method tied to fuel type for combustion emissions, which may involve carbon or heat value testing, or use of CEMS if present. Facilities below 25,000 metric tons of CO_2e per year would usually apply default emission factors.

In addition to the U.S. EPA core requirements, the ARB proposal requires reporting of additional descriptive information such as nameplate generating capacity and power generated; providing cogeneration descriptive information such as whether the unit uses topping or bottoming cycle and its thermal output; and applying additional specific missing data procedures that are required for all reporting facilities. The staff proposal would also require reporting of CO_2 and CH_4 by geothermal facilities based on emission factors obtained from source testing.

Petroleum Refineries. The proposed revised regulation is based on the U.S. EPA reporting regulation. This regulation would affect all California petroleum refineries where annual GHG emissions equal or exceed 10,000 MT of CO_2e. Methodologies are included for the calculation of GHG emissions from the following sources: stationary combustion, flares, catalytic cracking and fluid coking units, flexicoking units, catalytic reformers, sulfur recovery units, coke calcining units, asphalt bowing, delayed coking units, process vents, uncontrolled blowdowns, equipment leaks, and storage tanks. Refiners would also be required to report amounts of CO_2 captured and transferred off-site. Facilities that distill transmix are exempt from reporting.

Proposed changes from the existing ARB reporting rule include new methods for uncontrolled blowdowns and coke calcining, and removal of methods for fugitive emissions from wastewater treatment and oil/water separators. The two methods to be dropped are very minor sources with large uncertainties. The proposed rule also includes several changes that were deemed necessary to provide the requisite accuracy and consistency for a cap-and-trade program. Product output data would also be reported to support benchmarking for the cap-and-trade program.

Hydrogen Production. The proposed revised regulation will affect all hydrogen production facilities in California where GHG emissions equal or exceed 10,000 MT CO_2e annually, whether stand-alone merchant facilities or production units within larger facilities. Operators are required to report stationary combustion and process emissions as well as amounts of CO_2 captured and transferred off-site.

The proposed rule includes modifications to the U.S. EPA regulation that are necessary to ensure that the data reported are compliance grade for emissions trading. Operators would be required to sample feedstocks (other than natural gas) daily, but solid and liquid samples could be composited to produce a monthly sample for carbon content analysis.

Glass Production. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for glass production facilities. The proposed ARB regulation would affect approximately twelve California glass manufacturing facilities, which are also subject to the U.S. EPA reporting rule for greenhouse gases. Glass production facilities emitting 10,000 metric tons of CO_2e per year or more would be required to report emissions of CO_2, biomass-derived CO_2, CH_4, and N_2O from general combustion sources, biomass fired combustion units, and continuous glass melting furnaces using methods that are specified in the proposed regulation. Facilities would be required to report combined process-related and combustion CO_2 emissions from glass production using the CEMS methodology or separately report combustion emissions and process-related CO_2 emissions from glass production using the methods specified in the regulation. When separately reporting combustion emissions, glass production facilities would be required to follow fuel-specific methods, which may involve carbon or heat value testing. In addition, the facility would report quantities of fuel consumed, fuel characteristics, quantities of carbonate-based raw materials consumed, and annual production quantities of glass products to supporting benchmarking for the cap-and-trade program.

Lime Manufacturing. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for lime manufacturing facilities. The proposed ARB regulation is expected to affect a single lime plant in California that is also subject to the U.S. EPA reporting rule for greenhouse gases. It would be required to report combined process-related and combustion CO_2 emissions from the production of lime, calcined lime byproduct/waste that was sold, and calcined lime byproduct/waste that was not sold using the CEMS methodology or separately report combustion emissions and process-related CO_2 emissions from lime products and byproducts using the lime-based method specified in the regulation. When separately reporting combustion emissions, the lime plant would be required to report emissions of CO_2, biomass-derived CO_2, CH_4, and N_2O from lime kiln and other combustion sources by using fuel-specific methods, which may involve carbon or heat value testing. In addition, the facility would report quantities of fuel used, fuel characteristics, quantities of raw material consumed, annual production quantities for lime product, calcined lime byproduct/waste that was sold, and calcined lime byproduct/waste that was not sold, and other specified data.

Nitric Acid Production. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for nitric acid production facilities. The proposed ARB regulation would affect two California nitric acid production facilities, which are also subject to the U.S. EPA reporting rule for greenhouse gases. All California nitric acid production facilities would be required to report process-related N_2O emissions and combustion CO_2 emissions from the production of nitric acid. When reporting combustion emissions, the nitric acid plant would be required to report emissions of CO_2, biomass-derived CO_2, CH_4, and N_2O combustion sources by using fuel-specific methods, which may involve carbon or heat value testing. In addition, the facility would report quantities of fuel consumed and fuel characteristics. Nitrous oxide emissions would be reported using a site-specific emissions factor and production rate data or the operator may request approval from ARB's Executive Officer to use an alternative method, such as the use of N_2O CEMS, for determining nitrous oxide emissions. Annual nitric acid production data and other specified data would also be reported.

Pulp and Paper Manufacturing. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for pulp and paper facilities. The proposed ARB regulation would affect the five California pulp and paper facilities currently reporting, which are also subject to the U.S. EPA reporting rule for greenhouse gases. In addition, four to six additional facilities will likely be subject to abbreviated reporting due to the lower ARB reporting threshold. Pulp and paper manufacturing facilities emitting 10,000 metric tons of CO_2e per year or more would be required to report emissions of CO_2, biomass-derived CO_2, CH_4, and N_2O from general combustion sources, biomass fired combustion units, chemical recovery furnaces/combustion units, and pulp mill lime kilns, using methods that are specified in the proposed regulation. Facilities emitting 25,000 metric tons of CO_2e per year or more would be required to choose a calculation method tied to fuel type for combustion emissions, which may involve carbon or heat value testing, or use of CEMS if available.

Pulp and paper facilities would also be required to report CO_2 process emissions from makeup chemicals, if present. In addition, facilities would report quantities of fuel used, spent liquor solids combusted, fuel characteristics, quantities of $NaCO_3$ and $CaCO_3$ used, and annual production data to support benchmarking for the cap-and-trade program.

Iron and Steel Production. The proposed ARB reporting requirements are drawn from and similar to the U.S. EPA greenhouse gas reporting requirements for iron and steel production. The specific iron and steel reporting requirements proposed would affect only one California iron and steel facility, which is also subject to the U.S. EPA reporting rule for greenhouse gases. Other California steel facilities emitting 10,000 metric tons of CO_2e per year or more, such as those which produce rolled steel, pipe, or forgings, would also be subject to greenhouse gas reporting as a result of their general combustion emissions, but they would not be subject to the additional requirements for reporting process emissions. As proposed, an iron and steel production facility with specified sources and emitting 10,000 metric tons of CO_2e per year or more would be required to report emissions of CO_2, biogenic CO_2, CH_4, and N_2O from combustion sources. Facilities emitting 25,000 metric tons of CO_2e per year or more would be required to choose a calculation method tied to fuel type for combustion emissions, which may involve carbon or heat value testing, or use of CEMS if available. An iron and steel facility would compute and report process emissions from any electric arc furnace (EAF), argon-oxygen decarburization vessel, direct reduction furnace, or other specified sources. Iron and steel facilities would also be required to report annual production information and other specified data to support benchmarking for the cap-and-trade program.

6. Overview of Requirements for Fuel and CO_2 Suppliers

Suppliers of Transportation Fuels. The proposed revised regulation will affect all suppliers of transportation fuels in the State of California where annual amounts of supplied, produced or imported fuel, when completely combusted or oxidized, equals or exceeds 10,000 metric tons carbon dioxide equivalent. The proposed revised regulation will also affect all refiners that produce liquefied petroleum gas without regard to quantity. This requirement includes position holders, enterers, producers of biomass-derived fuels and refiners. In the current ARB regulation refiners are only required to report combustion and process emissions and not emissions from produced fuel combustion, none of the other listed entities are required to report. U.S. EPA methods are used for calculating emissions from all fuels.

Suppliers of Natural Gas, Natural Gas Liquids and Liquefied Petroleum Gas. The proposed revised regulation will affect all suppliers of natural gas, and consignees who import liquefied petroleum gas (LPG) into California where annual amounts of supplied or imported fuel, when completely combusted or oxidized, equals or exceeds 10,000 metric tons of CO_2e. The proposed revised regulation will also affect all natural gas liquid fractionators without regard to quantities supplied. This requirement includes operators of interstate and intrastate pipelines, local distribution companies who are public utility gas corporations or publicly-owned natural gas utilities, liquefied petroleum gas consignees that import LPG into California, and natural gas liquid fractionators. In the current ARB regulation, natural gas liquid fractionators and public utility gas corporations are only required to report combustion and process emissions from stationary sources and not emissions from supplied fuel combustion, none of the other listed entities are required to report. U.S. EPA methods are used for calculating emissions from all fuels.

Suppliers of Carbon Dioxide. The proposed revised regulation will affect all suppliers of carbon dioxide in California where amounts of produced or imported CO_2 annually equal or exceed 10,000 metric tons. This requirement includes facilities which capture and transfer a CO_2 stream for commercial applications, facilities with CO_2 production wells, and importers and exporters of bulk CO_2. In the current ARB regulation only petroleum refineries with hydrogen production facilities and merchant hydrogen plants were required to report transferred CO_2. U.S. EPA methods are included for facilities where CO_2 is produced and captured (i.e. hydrogen production facilities) and for bulk importers and exporters of CO_2. Operators must also report the quantity of CO_2 transferred for thirteen end-use applications (i.e. food and beverage, pulp and paper) if known. Separate reporting of quantities imported into or exported from California is required under the staff proposal.

7. Overview of Requirements for Petroleum and Natural Gas Systems

The ARB staff proposal is based on the proposed U.S. EPA Subpart W draft rule for Petroleum and Natural Gas Systems and would affect all petroleum and natural production operations in California where an entity's emissions equal or exceed 10,000 metric tons of CO_2e annually within a geologic basin. GHG emissions would be reported for:

- Offshore petroleum and natural gas production;
- Onshore petroleum and natural gas production;
- Onshore natural gas processing plants;
- Onshore natural gas compression;
- Underground natural gas storage;
- Liquefied natural gas (LNG) storage;
- LNG import and export equipment;
- Natural gas distribution.

The draft U.S. EPA Subpart W rule was evaluated and modified by WCI where it was determined that changes were necessary to ensure data generated was cap-and-trade quality, to correct errors, and to provide more workable methodologies. When the U.S. EPA Subpart W Rule is made final, ARB will reconfigure this article to conform with the existing California MRR format.

In the case of onshore petroleum and natural gas production, the reporting footprint is defined as the geological basin. Reporters would be required to determine and report emissions from stationary combustion, and specified process and vented emissions. Under the current ARB reporting regulation, these facilities are required to report only stationary combustion emissions if they equal or exceed a 25,000 metric tons of CO_2 threshold.

The WCI harmonization process resulted in recommendations that seven of the draft U.S. EPA methodologies be adopted without changes. For several source categories (storage tanks, field gas combustion, and venting of pneumatic devices and pumps) the staff proposal includes changes in methods, and added monitoring equipment to support them. These changes were recommended because WCI concluded that the proposed U.S. EPA methodologies would not generate compliance-grade data to support cap-and-trade. The proposal also includes several minor changes to correct errors in calculation methodologies and improve data quality to a level appropriate for a cap-and-trade program. In addition, two of the U.S. EPA reporting methodologies were not included in the staff proposal because of source insignificance or the decision to propose a more accurate method for the source category.

8. Overview of Verification Requirements

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 continue to be performed by qualified, trained, and ARB-accredited third-party verifiers that meet specifications for education and experience, and demonstrate that there is no conflict of interest for verifying the emissions data report due to current or previous relationships with the reporting entity. All verifiers would have to demonstrate knowledge of the proposed regulation to provide verification services for California's mandatory GHG reporting program to support the cap-and-trade program.

Only an ARB-accredited verification body may submit a verification statement on behalf of a reporting entity. Each accredited verification body must have at least two lead verifiers and five total staff. ARB currently has about 230 accredited verifiers and 45 accredited verification bodies. New lead verifiers, general verifiers, sector specific verifiers, and verification bodies will be trained and accredited as needed. The current reporting regulation allows local air quality management districts and air pollution control districts (local districts) to apply for accreditation as verification bodies. ARB staff is continuing to work with local districts to better define the process that allows local districts to provide verification services.

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 statement submitted to ARB and the reporting entity. These and other elements of verification services are discussed in detail in Section IV of this report.

II. GREENHOUSE GAS GENERAL REPORTING REQUIREMENTS

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

A. General GHG Reporting Topics and Issues

1. Selection of Sources

The Initial Statement of Reasons for the current ARB GHG reporting regulation (ARB 2007) states that:

> 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.

ARB staff considered several factors in the selection of the additional sources for mandatory reporting. With other Western Climate Initiative (WCI) jurisdictions, California shared a design commitment to develop a broad, economy-wide market trading program, and ARB worked with other jurisdictions represented on the WCI Reporting Committee to develop Essential Requirements for Mandatory Reporting for 18 industrial sectors to support such a program (WCI ERMR 2009). WCI identified an additional 14 sectors for additional work. Meanwhile the U.S. EPA completed rulemaking on a broad-scope federal mandatory reporting rule, with 40 separate industrial sectors identified for reporting. ARB staff reviewed both the WCI Essential Requirements and the U.S. EPA rule relative to the occurrence of source types in California.

Following participation in work through WCI to harmonize its reporting requirements with the U.S. EPA regulation, staff identified 15 source sectors, including nine new sectors, that occurred in California and for which rigorous and consistent methods were available to calculate fossil fuel combustion and process emissions. In most cases those methods were identified as options or requirements in the final U.S. EPA regulation (USEPA MRR 2009-2010).

ARB has two additional source categories which are not included in the U.S. EPA regulation. Electric power entities, required to report under the current ARB regulation (ARB MRR 2007), continue to report to address specific AB 32 requirements to account for imported electricity.[6] Petroleum and natural gas systems were added following U.S. EPA's proposal to add reporting of oil and gas production, processing and storage

[6] AB 32 specifically requires an accounting of "greenhouse gas emissions from all electricity consumed in the state," including imported electricity. California Health & Safety Code §38530(b)(2).

sources to federal reporting requirements. Final action on this U.S. EPA proposal is expected this fall.

2. Selection of Reporting Thresholds

In their 2008-09 Program Design Recommendations, the WCI Partners expressed the desire to monitor what happens beneath the agreed-upon cap-and-trade threshold of 25,000 metric tons (MT) of carbon dioxide equivalent (CO_2e) (WCI Design Recommendations 2009). The Partners adopted a reporting threshold of 10,000 MT of CO_2e to enable monitoring for leakage of emissions from sources below the cap threshold, and to assess whether the cap threshold was appropriately set. The Partners wanted to be able to recommend subsequent action if the cap threshold had unanticipated economic or emissions consequences, and the lower reporting threshold would inform their review of market impacts. In addition the Partners recognized the 10,000 MT CO_2e threshold had been included in proposed federal climate change legislation (US HR2454 2009).

ARB staff considered a reporting threshold of 10,000 MT of CO_2e during rule development in 2007, which had been proposed by some stakeholders. At that time, staff decided that a threshold of 25,000 metric tons of CO_2e would, for most sources, cover a sufficient proportion of point source emissions for the initial reporting program. That threshold, along with a 2,500 MT CO_2e threshold for electricity generating and cogeneration facilities rated 1 megawatt or higher, was included in the adopted 2007 regulation.

Staff has since carefully weighed the impacts of lowering the threshold to match the WCI design recommendation. A 10,000 ton threshold is likely to affect smaller businesses in California, and there was concern about imposing the burden of reporting on about 150 facilities affected for the first time. On the other hand, it seemed important to be able to monitor the effects of the cap-and-trade threshold on both emissions leakage below the cap and on business competitiveness above it. As a result, we are proposing inclusion of the lower threshold, but also proposing a more limited and simplified reporting requirement for facilities under the cap-and-trade threshold, as discussed below.

Staff is also proposing that the threshold for electricity generating and cogeneration facilities be raised from 2,500 MT CO_2e to the same 10,000 MT CO_2e level as other facilities. The emissions that would not be reported to ARB by the 50 affected facilities is less than ¼ of 1 percent of the inventory, and these emissions can be estimated through data reported to other agencies, including the California Energy Commission and Energy Information Administration (ARB GHG Inventory for 2000-2008). A common threshold for electricity and other facilities is also more equitable.

Staff also recognized that the U.S. EPA regulation has no threshold for some types of facilities, including cement production, lime manufacturing, nitric acid production, petroleum refineries, and electricity generating units already reporting under 40 CFR Part 75. For these facility types, and for natural gas liquid fractionators and producers of carbon dioxide, no threshold is proposed in the revised regulation, which is consistent with U.S. EPA requirements.

Abbreviated Reporting for Facilities Emitting Less Than 25,000 Metric Tons of CO_2e. In opting to propose the 10,000 metric ton CO_2e threshold consistent with other WCI jurisdictions, staff has attempted to mitigate the reporting burden through inclusion of an abbreviated reporting option. The option would apply to facilities emitting less than 25,000 MT of CO_2e, provided they do not otherwise have a cap-and-trade compliance obligation or federal GHG reporting obligation. Eligible facilities would submit a simplified report with fewer fields. They would not need to install new monitoring equipment nor have their reports verified by a third party verification body. (All reports are potentially subject to ARB audit.) They could select default emission factors by fuel type for combustion and report fuel use. The relatively few facilities that may have process emissions to report would be able to use any method permitted in the U.S. EPA regulation to calculate process emissions. Facilities generating electricity above the threshold would include basic information about their generating systems and cogeneration systems if applicable. In addition, a later June 1 deadline is proposed, to allow these facility operators additional time to complete and submit their reports.

Staff believes the abbreviated reporting option is appropriate because it minimizes the reporting burden for facilities emitting between 10,000 and 25,000 MT of CO_2e, while providing decision makers the information needed to fully monitor the effects of a cap-and-trade program. The abbreviated reporting option would not apply to suppliers as explained in Section III.

The reporting threshold for imported electricity was given careful consideration to assure fair and equitable treatment of in-state and out-of-state electricity generation resources. The cap-and-trade compliance threshold for first deliverers of electricity applies to emissions attributed to specified facilities inside and outside of California. Specified facilities with emissions less than 25,000 MT of CO_2e will receive an emission factor of zero MT CO_2e/MWh imported into California.

Reported electricity deliveries imported into California have no threshold for the following reason: Consistent with the physical operation of the Western Interconnection, electrons cannot be traced from load back along physical pathways to specific electricity generating facilities. Due to this physical reality of the shared transmission system, all imported electricity must be treated as unspecified power from resources in the western region capable of providing power on demand, or on the margin. Importers must assure chain-of-custody through ownership share or written contracts in order to claim sources of power other than unspecified power from the western region. Importers that receive electricity from asset-controlling suppliers and multi-jurisdictional retail providers recognized by ARB must also report these deliveries as specified to assure emissions are calculated based on the system power attributes of these suppliers.

3. Reporting and Verification Schedules

At the March 23, 2010 workshop staff proposed, as part of the effort to harmonize state and federal reporting requirements, that annual emissions data reports be due to ARB on the same date as reports are due to U.S. EPA, March 31. In response to the proposed March 31 date, the comment heard most often at the workshop was that this date was not workable for the electricity retail providers expected to compile and report electricity imports data. Electricity retail providers indicated that the data they rely on from other parties is generally not available to the retail provider until later in the spring. In addition, electricity retail providers do not report to U.S. EPA, so a similar reporting date need not apply to them.

Staff reviewed this issue after the workshop, consulted further with several retail providers, and agreed that a later deadline was warranted. Therefore, and consistent with the current ARB GHG reporting regulation, the regulatory proposal includes two reporting deadlines, April 1 and June 1. The April 1 deadline would apply to all facilities and suppliers who have a federal reporting obligation or a cap-and-trade compliance obligation. The June 1 deadline would apply to all remaining reporters, including electric power entities and lower-emitting facilities not subject to cap-and-trade.

In the current ARB GHG reporting regulation, verification deadlines are October 1 (for April 1 reporters) and December 1 (for June 1 reporters). In order to allow time for annual true-up in the proposed cap-and-trade program, which needs to be completed before auctions during each year of a compliance period, it is necessary to move up the verification deadlines. Staff is therefore proposing deadlines of September 1 for those whose reports are due April 1, and October 1 for those whose reports are due June 1. This will shorten the time available for verification from six months to five months for April 1 reporters, and to four months for June 1 reporters. ARB staff believes that with efficiencies gained as everyone becomes more familiar with the verification process, with fewer verifications due overall, and with less complex reports expected for electric power entities, the more limited period is workable. Reporting entities also have the option to report ahead of reporting deadlines to allow more time for verification.

4. *De Minimis* Emissions Sources

The staff proposal retains the general framework and limits for reporting emissions as *de minimis* as permitted under the current regulation (ARB MRR 2007). This is in contrast with the U.S. EPA regulation, which has no explicit *de minimis* provision. The U.S. EPA regulation often offers a greater number of options, including less rigorous options, for calculating and reporting emissions. And some emissions do not require reporting. However, given the need for rigorous and highly accurate accounting of the emissions that may be subject to a cap-and-trade program, the proposed ARB regulation is more prescriptive for most sources at affected reporting entities.

So why permit *de minimis* reporting at all, then? Staff recognized that despite the need for high accuracy reported by a facility's overall inventory, there are some very minor sources for which the methods specified in the proposed regulation would be overly prescriptive and costly. Allowing emissions from these sources to be handled with "lower tier" methods would not risk a material misstatement for the facility because the sources are too minor. And because the proposed regulation is more prescriptive, the need for *de minimis* reporting, with appropriate limitations, becomes more acute.

The staff proposal would limit emissions claimed as *de minimis* to specific emissions chosen by the operator that represent no more than 3 percent of total facility emissions, not to exceed 20,000 metric tons of CO_2e emissions. Emissions would still be estimated and reported for the selected *de minimis* sources, but alternative emission estimation methods could be used.

There is some adjustment of the *de minimis* language in the proposal for the revised regulation, such as more direction for what verifiers should consider when assessing sources reported as *de minimis*. In particular, where such emissions have been calculated and reported to U.S. EPA under the requirements of 40 CFR Part 98, the operator would be required to report them similarly to ARB. The U.S. EPA requirements thus become a "floor" for emissions that they cover.

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, subject to the limitations above. Such *de minimis* emissions would still be reported to assure the completeness of the emissions data report, and the chosen estimation methods would remain subject to the verifier's oversight and professional judgment that they are reasonable and unbiased.

5. Enhancements to Monitoring Requirements

The staff proposal incorporates most of the general monitoring requirements of 40 CFR Part 98, Subpart A. Some additional requirements are included in the proposal to safeguard data collection for the cap-and-trade program. These are discussed below.

<u>Measurement Device Calibration and Accuracy</u>. The current ARB regulation requires facility operators to "employ procedures for fuel use data measurements that quantify fuel use with an accuracy within ±5 percent" (ARB MRR 2007). The regulation further requires measurement devices to be "maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy." The staff proposal essentially replaces this requirement with the similar requirements at 40 CFR §98.3(i), which require measurement device calibration according to the manufacturer's recommended procedures, an appropriate industry consensus standard, or a method specified elsewhere in the federal regulation. The federal rule requires all measurement devices to be calibrated to an accuracy of ±5 percent, with initial calibrations to be conducted in most cases by April 1, 2010.

40 CFR §98.3(i) adds specific requirements by type of flow meter. Fuel billing meters are exempted from the calibration requirements, unless the fuel supplier owns both the

meter and the unit combusting the fuel. The federal requirements then make another exception that is qualified in this staff proposal.

Under 40 CFR §98.3(i)(6), an operator may postpone initial calibration of measurement devices if it would require "removing the device from service and shipping it to a remote location, causing a disruption of normal process operation. In such cases, the owner or operator may postpone the initial calibration until the next scheduled maintenance outage, and may similarly postpone the subsequent recalibrations." The postponements must be documented in the monitoring plan required by the regulation.

Concerned about the potential for indefinite postponement of calibrations that would ensure fuel use measurement accuracy, WCI initially proposed that calibrations be required during the next facility maintenance period, regardless of whether or not it was scheduled. Commenters objected because unscheduled maintenance periods are not of predictable duration to ensure enough time for calibration when the meter must be removed from service. WCI's Reporting Committee agreed and settled on alternative language.

ARB staff considered WCI's proposed language and established that it would be effective for meeting the needs of ARB programs. For facilities in the cap-and-trade program the staff proposal thus includes a requirement that when meter calibration is postponed as documented in a monitoring plan, the ARB Executive Officer is to be notified of the reasons for the postponement and the date when calibration will be completed. Such postponements would be subject to his or her approval. This is to prevent potential abuse of the U.S. EPA allowance of indefinite postponement of measurement device calibration when measurement accuracy is critical. It would apply only to postponements after January 1, 2012. Though we expect calibration postponements to be relatively rare – operators share an interest in accurate monitoring under a cap-and-trade program – this additional requirement will serve the purpose of informing ARB staff of potential measurement problems at specific facilities, and taking corrective action where important to the integrity of emissions estimation.

Weekly Monitoring of Fuel Use Data. The proposed regulation augments the U.S. EPA requirement to maintain a written GHG Monitoring Plan by requiring the plan to include regular checking of fuel measurement equipment when it is used to calculate GHG emissions. At least weekly, affected operators (those above 25,000 MT of CO_2e who do not use CEMS to report GHG emissions) would be required to monitor fuel measurement equipment and maintain records of its proper operation.

As discussed in this report, staff believes it is necessary to include separate requirements for the substitution of missing fuel analytical data in the proposed regulation. In turn it is necessary to collect data that would be needed to support the missing data substitution procedures for fuel use. This would include recording weekly fuel use data (daily data is warranted in some situations, but this would not be required). By recording regularly the amount of fuel consumed, the operator builds a base of data that can be drawn upon if it becomes necessary to substitute for missing data when equipment breaks down. The operator benefits from this active monitoring because the weekly or daily data collected reduce or eliminate the need for more punitive data substitution in a missing data situation. The records of fuel consumption should be sufficient for the application of the missing fuel use data substitution procedure in section 95129(d)(2) of the regulation, in case the use of that procedure becomes necessary.

6. Reporting of Electricity and Heat/Steam Purchases

Staff has proposed to continue the reporting of electricity and heat or steam purchases by facilities, but not extend it to suppliers or other reporting entities. Such information would still be reported, by each provider, in kilowatt-hours (kWh) for electricity received and British thermal units (Btu) for heat, cooling or steam. This information is not required under current U.S. EPA or WCI reporting requirements, but is usually required in reports to voluntary registries. Unlike reporting to voluntary registries, energy purchases reporting to ARB does not require an emissions calculation, but information is collected that would enable such calculations by ARB.

Although there is no compliance obligation proposed for purchased energy under the proposed cap-and-trade program, the information required under the current reporting regulation is being used for benchmarking and other analyses related to cap-and-trade program development, and is expected to assist program implementation. The information has also proven important for other ARB GHG control strategies, and will be used in particular to support implementation of the energy efficiency and co-benefits audits regulation. As has been past practice, any indirect emissions calculations would be estimated in an entirely separate accounting framework to avoid any potential double-counting.

Indirect energy usage also 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 increases the conservation awareness of the facility and provides information to ARB as we consider future strategies related to industrial sectors. For these reasons, we have included the requirement to report indirect energy usage in the staff proposal.

7. Clarity of Terms for Who Reports

In the current GHG reporting regulation, the term “operator” is applied to anyone who reports, even those reporting electricity transactions. In the U.S. EPA regulation, reporting is done by facilities or suppliers, and the term “operator” applies to “the person who operates or supervises a facility or supplier.” With several types of entities responsible for reporting, and different provisions of the proposed regulation applying differently to these different types of entities, it is important that these terms be applied consistently within the proposed revised regulation – and consistently with U.S. EPA’s usage in their reporting regulation –to avoid confusion and because the proposed ARB regulation refers repeatedly to provisions of the federal regulation.

Thus, in the proposed revised regulation the broad term we are applying to everyone who reports is “reporting entity.” The reporting entity may be either a facility operator, a supplier of fuels or carbon dioxide, or an electric power entity. Each has separate reporting obligations, but there may be some operators who also report as suppliers (e.g., petroleum refineries).

ARB staff has tried to apply these terms selectively. We use “reporting entity” when we mean anyone who reports. Some provisions apply to facility operators only, and some to facility operators and suppliers but not electric power entities, so in such cases we have tried to be specific. Also, within a reporting sector, additional terms may apply. The provisions that apply to retail providers who do not import or export electricity from California are more limited, so a distinction by type of electric power entity is made. The type of fuel supplier is specified in sections 95121 and 95122, because requirements vary among position holders, enterers, and fractionators, as examples. And the term “facility operator” may be shortened to “operator” within a section of the regulation that addresses only a particular type of facility. It is important when the reader is in doubt about an interpretation to consult the definitions in the regulation.

8. Non-Submitted/Non-Verified Emissions Data Report

For a reporting entity in the cap-and-trade program, the verified emissions data report is the basis for their compliance obligation. Language was needed to address the situation where a reporting entity may fail to submit an emissions data report by the applicable reporting deadline or fail to have an emissions data report verified by the applicable verification deadline. In all cases, it is best for the reporting entity to submit a verified emissions data report on time that accurately represents its GHG emissions and forms the basis of its obligation in the cap-and-trade program. In the absence of a verified emissions data report, the Executive Officer will now look at several factors to develop an assigned emissions level for the reporting entity. These factors include looking at the general days and hours of operation for the reporting entity and the maximum emissions associated under those conditions. The Executive Officer will also evaluate and consider any related data submitted for any other regulatory purposes. This method not only ensures a conservative calculation of the reporting entity’s emissions, but hopefully encourages all reporting entities to comply with the regulation.

9. Enforcement

The goal of the proposed revised GHG reporting regulation remains the same as the goal of the current GHG reporting regulation – to collect complete and accurate GHG emissions data from those subject to reporting. The revised regulation includes the additional goal of providing stringent, accurate emissions data to support the proposed cap-and-trade program. Based on ARB’s experience with the current GHG reporting regulation, and in order to address the stringency needed to support the proposed cap-and-trade program, the enforcement provisions of the current GHG reporting regulation have been revised.

Since the implementation of the current GHG reporting regulation, ARB staff has worked closely with reporting entities, third-party verification bodies, and verifiers to assist them in complying with the regulation. This has included providing guidance documents, training, workshops, on-line reporting tools, and having staff readily available to answer questions. ARB staff will continue to provide this assistance with regards to the proposed revisions described in this staff report, including the revised enforcement provisions. The enforcement provisions of the proposed revised regulation are contained in section 95107.

Violations. Section 95107 makes clear what constitutes a violation of the proposed revised GHG reporting regulation. The revised provisions clarify the number of days, or portions thereof, of violations for failing to comply with the revised regulation. For instance, if an emissions data report is not submitted, is submitted late, or contains incomplete or inaccurate information, each day or portion thereof that the report is late will constitute a separate violation of the proposed regulation. The section also clarifies what is meant by "inaccurate." In this instance, "inaccurate" means that the information is not within the level of reproducibility of a test or measurement method required by the proposed regulation. These same violations would result if a verification body fails to submit a verification statement by the required deadline in the proposed regulation (see proposed revised section 95103(f)). Each day or portion thereof that the verification statement is late would constitute a separate violation of the proposed regulation. Furthermore, given that section 95103(f) requires the reporting entity to obtain the services of a verification body and that such services must be completed by the regulatory deadline, a late submitted verification statement could also lead to a violation by the reporting entity.

In addition, this section also clarifies that each failure to comply with the methods in the proposed regulation for measuring, collecting, recording, and preserving information needed for the calculation of emissions constitutes a separate violation of the proposed regulation. This violation has been included in the proposed revisions because it ensures that reporting entities will utilize the methods required by the regulation, which further ensures the stringency of calculations and resulting reported emissions data. This provision is also consistent with 40 CFR §98.8 of the U.S. EPA Mandatory Reporting Rule (U.S. EPA MRR 2009).

Moreover, in order to maintain consistency with the proposed cap-and-trade program and other AB 32-related regulations, the proposed revisions clarify that the failure to accurately report GHG emissions data will result in a separate violation for each metric ton of CO_2e emitted but not reported as required by the proposed regulation. As mentioned above, the proposed revisions are necessary to ensure accurate and stringent emissions data in order to support a cap-and-trade program, and this violation is designed to ensure that reporting entities accurately report their GHG emissions to ARB and that the number of violations directly reflects the amount of CO_2e emissions. A metric ton was selected as the essential unit of violation for unreported emissions because metric tons are the basic unit both for reporting emissions and for allocations under the proposed cap-and-trade regulation. By using metric tons, the number of violations will remain proportional to emissions, which is in keeping with the statute's overall intent to reduce emissions. In addition, existing enforcement statutes direct ARB to consider, when determining administrative penalties, the "extent of harm caused by the violation," and the "nature and persistence of the violation." (Health & Safety Code (H&SC) §§ 42410(f) and 42403.5(b)(1)(2)). Proposed regulation section 95107(c) makes specific that the "extent of harm" and the "nature" of a failure to report will be analyzed, for penalty purposes, in terms of metric tons. A similar violation is included in the proposed cap-and-trade regulation, as well as the proposed Renewable Electricity Standard regulation (*see* proposed Title 17, *California Code of Regulations* (CCR), section 97009).

Finally, the current regulation included the "knowing submission of false information, with intent to deceive" as a separate violation. As noted by the WCI in its *Response to Stakeholder Comments and Final Draft Essential Requirements for Mandatory Reporting* (WCI Response to Comments 2009), strict liability is the normal standard for the imposition of civil liability in environmental regulatory programs. In fact, AB 32's enforcement provisions expressly incorporate existing strict liability enforcement statutes such as H&SC sections 42400 and 42402 without any statutory language indicating an intent to require a higher, narrower standard of 'knowing' or 'intent to deceive' in every instance. Other ARB environmental regulations, including the Low Carbon Fuel Standard (Title 17, CCR, section 95484(e)) and the Airborne Toxic Control Measure for Auxiliary Diesel Engines Operated on Ocean-Going Vessels At-Berth in a California Port (Title 17, CCR, section 93118.3(h)), use the normal strict liability standard, rather than the knowing, with intent to deceive standard. Stakeholders have raised the same concerns addressed in the WCI Response to Comments 2009 with ARB. In order to ensure consistent enforcement with other ARB environmental regulations, and in accordance with the WCI, the proposed revised regulation has replaced the "knowing submission of false information, with intent to deceive" standard of liability with a strict liability standard.

<u>Penalties</u>. The proposed revised enforcement provisions implement and make specific H&SC 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 H&SC. Moreover, consistent with H&SC section 38580, the proposed revised regulation provides that the following remedies are available for a violation of any GHG reporting regulation provision:

(1) Civil and criminal penalties under H&SC § 42400 et seq.; and
(2) Injunctive relief under H&SC § 41513.

In addition, the proposed revisions clarify that the Executive Officer may revoke or modify any Executive Order issued under the proposed regulation as an additional sanction for violating the requirements of the proposed regulation.

It is important to emphasize that ARB's goal is to collect accurate GHG emissions data to support ARB's GHG inventory and proposed cap-and-trade program, not to collect penalties. As we have for the current GHG reporting regulation, we will continue to work closely with those subject to reporting and our third-party verifiers to assure that we can meet this goal.

ARB Enforcement Actions. Enforcement and compliance assurance of the proposed revised GHG reporting regulation could involve some or all of the following ARB staff activities:

- Receipt of annual GHG emissions data reports from reporting entities;
- Accreditation process for verification bodies and verifiers;
- Conflict of interest assessments of verification bodies;
- Receipt of verification statements from verification bodies for each reporting entity's GHG emissions data report, when applicable;
- Review of the reports and verification statements for completeness and accuracy;
- Evaluation of emissions data in the emissions data reports to determine if the reporting entity is in compliance with the requirements of the GHG reporting regulation;
- Inspections or audits of the reporting entities and verification bodies to verify and validate the information submitted in the reports and verification statements, and to verify and validate that reporting entities are utilizing the methods required by the GHG reporting regulation;
- Preparation and issuance of notifications of violation;
- Meeting with violators for the purpose of mutual settlement;
- Participation in litigation, if necessary.

The enforcement process would begin when a possible violation of a requirement of the regulation is detected by or brought to the attention of ARB. A violation may be brought to the attention of ARB by a wide variety of sources, including through self-reporting. Self-reported violations are generally considered more favorably in the enforcement process. Once ARB has been made aware of a violation, ARB gathers all available information and makes a final determination as to whether a violation has in fact occurred. If ARB determines that a violation has occurred, ARB will notify the party involved. Such notification would set forth the basis for ARB's determination, the regulatory requirements violated, and any proposed penalty.

ARB anticipates that most violations will be resolved promptly. In unusual cases, ARB or the party involved may wish to schedule an office conference, providing the party with the opportunity to present any mitigating information the party believes is relevant to the matter. Based on the information provided, ARB will review its findings and, if it still determines that a violation has occurred, ARB will propose a resolution. A resolution may be comprised of a financial penalty, determined based on the factors as set out in H&SC § 42403. These factors include: frequency of past violations, the duration of the violation, the nature and persistence of the violation, the financial benefit gained by the violator, actions taken to ameliorate the violation, and the financial burden to the violator. ARB may also propose certain action measures designed to minimize the potential for further violations.

ARB's overall enforcement goal is to assure compliance with all regulatory requirements, and its enforcement efforts, in any enforcement situation, begin with bringing the party back into compliance. Once compliance has been achieved, ARB's enforcement efforts are focused on deterring future noncompliance.

B. GHG Data Reporting Submittals and Recordkeeping

1. GHG Reporting Mechanism

As staff indicated at the March 23, 2010 workshop, we are working closely with U.S. EPA in an attempt to develop a unified reporting system for state and federal GHG reporting. U.S. EPA has indicated a strong desire to assist states in meeting the needs of their GHG reporting and control programs, and we hope to have this system in place by 2012, in time for the initial year of reporting under the revised regulation.

Under both the current regulation and this staff proposal, reporting entities must submit reports to ARB using the ARB GHG Reporting Tool "or any other reporting tool approved by the Executive Officer that will guarantee transmittal and receipt of the data required." ARB staff is working with U.S. EPA to attempt to enable their reporting framework, supplemented if needed with a mechanism for additional data submittal to California, to serve that purpose.

2. 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 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 in order to provide complete summary information for a calendar year. Unverified data would be flagged as unverified. GHG emissions data reported under the revised regulation would be available through ARB websites beginning in 2012.

3. Designation of Confidential Information

Stakeholders subject to reporting have sometimes 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 continue to 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 reporting entities to report both emissions data and non-emissions data. 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.

Reporters to U.S. EPA should be aware that the agency has proposed special rules to address the confidentiality of data submitted under their regulation. The July 7 proposal can be found at http://edocket.access.gpo.gov/2010/pdf/2010-16317.pdf. Given that certain information reported to U.S. EPA will be designated by U.S. EPA as non-confidential (e.g., public), ARB staff proposes to consider this same information as public for purposes of the proposed revised regulation.

C. Missing Data Substitution Procedures

In assessing the suitability of the U.S. EPA reporting rule for cap-and-trade, it became readily apparent that many of the provisions for substitution of missing data could be easily subject to abuse. Aware that the incidence of missing data substitution is low in the Acid Rain Program, due to its stringency in support of market trading, ARB staff looked to Part 75 as a model (USEPA Part 75)for missing data provisions in the proposed revised regulation.

Accurate emissions accounting is essential for the state's emission inventory, for informing other climate programs, and for a market-based program to reduce GHG emissions. The emissions collected under the GHG reporting rule form the basis for trading in a carbon market. The fuel monitoring and sampling requirements as well as emission calculation methods in the proposed rule enable sound emissions accounting. However, because emissions are either measured directly by CEMS or calculated from measured fuel/feedstock data, and in practice measurement equipment and fuel sampling system may occasionally malfunction, additional requirements to address missing data are necessary to ensure the parameters used to estimate emissions are fully accounted. If some of these required data are missing, emissions can be underestimated, resulting in the reporting entity being responsible for a smaller compliance obligation and creating a perverse incentive to miss more data. This can open up opportunities for gaming the cap-and-trade system. For these reasons, a regulatory prescription for how to substitute for missing data is imperative for ensuring the integrity of the carbon market.

1. Review of U.S. EPA Approach

In its GHG reporting rule, U.S. EPA attempts to address missing data substitution for stationary fuel combustion in Subpart C and in each industry-specific subpart for process emissions. In 40 CFR §98.35, the U.S. EPA requires operators to substitute missing fuel characteristic data (e.g. high heat value, carbon content, and moisture content) using the average of measured values immediately before and after the missing data period, and substitute missing fuel consumption and flow rate data using the best available estimate, while requiring Part 75 (Acid Rain Program) sources to follow the existing missing data substitution procedures in Part 75 . ARB staff finds that the Part 75 approach (USEPA Part 75) is sufficiently stringent to support cap-and-trade. Part 75 takes a tiered, increasingly more punitive approach in data substitution, such that the more data are missed, the increasingly more conservative (higher) value must be used for substitution. It produces higher emissions numbers and an incentive for operators to achieve a high data capture rate, especially when a carbon price is in place.

However, for non-Part 75 sources, ARB staff finds that U.S. EPA's approach in Part 98 leaves data substitution methods largely to the operator's discretion and is not sufficient for supporting a cap-and-trade program. First, the U.S. EPA approach gives operators much latitude in choosing a data estimation method, which can make it difficult for verifiers to validate the credibility of the operator's chosen method and can generate significant need later for ARB staff to review and interpret each estimation case. Second, substitution using "before" and "after" values can potentially leave out periods of peak production and underestimate emissions, if the "before" and "after" values are lower and not representative of the missing production period. Third, the U.S. EPA's data substitution approach does not put a limit on the amount of data that could be missing from a year, which can potentially undermine the data quality. Last, the difference in stringency of the data substitution requirements for Part 75 units and non-Part 75 units presents an inequality issue for regulated entities. For these reasons, staff believes that more prescriptive data substitution procedures must be included in the revised GHG reporting rule to ensure data quality and equity in emission accounting for cap-and-trade.

2. Proposal for Missing Data Substitution

In writing prescriptions for missing data substitution, staff looked to 40 CFR Part 75 (revised as of July 1, 2009) (USEPA Part 75) as a model because 40 CFR Part 75 is an existing market-based program that has had success achieving its objectives. Staff identified the data parameters that need more stringent missing data substitution procedures beyond what is in the U.S. EPA's Part 98 GHG reporting rule and applied a similar tiered, increasingly punitive concept of Part 75 in writing the new substitution procedures.

Unit Reporting Emissions Using CEMS. For Part 75 units, which are reporting their CO_2 emissions using CEMS operated in accordance to Part 75 rules, staff's proposal is consistent with the U.S. EPA requirements. For other non-Part-75 units that report CO_2 emissions using CEMS, staff proposes to require the operators to substitute missing data according to Part 75 requirements. This will level the playing field among all sources that report emissions using CEMS.

Fuel Characteristic Data. Fuel characteristic data, such as high heat value and carbon content, generally have a range of values that is not arbitrary by definition, and the variations in values tend to be reasonably bounded. Therefore, staff determines that if a facility is missing a small amount of data (<10%), substituting with the average of the "before" and "after" values consistent with the U.S. EPA rule provides a reasonable estimate. Staff further creates 2 additional tiers of data substitution. If triggered due to percent data capture rate falling below 90% and 80%, the operator is required to substitute the missing value with the highest value recorded in 3 years or in all records kept, respectively. To ensure that the substituted value is at least as conservative as the default heat contents of 40 CFR Part 98 and the default carbon contents of Part 75, staff proposed to require the operator to use the greater of the default value or the highest value in facility records for substitution.

Fuel Consumption Data. For substitution of missing fuel consumption data, as long as the annual total facility level fuel consumption can be accurately determined, so that the annual total emissions can be accurately calculated and compliance obligation appropriately assessed yearly, the operator has leeway in estimating missing fuel consumption data at the sub-facility level using the best available estimate method. Because facilities typically have fuel metering at different levels (for example, a revenue meter at the facility level and other meters at the unit level), operators must be able to match up the fuel use records at the different levels at the end of the year, which result in the best available estimates to true up to the annual facility fuel use quantity. In this case, there is no concern with operators potentially gaming the system because the true up of fuel records must be verified by a third-party verifier. However, in the unlikely scenario that the facility level fuel consumption cannot be accurately determined, and the unit fuel consumption is also missing, staff prescribes stringent missing data substitution procedures to be applied at the unit level.

Unlike fuel characteristic data which generally has a range of values by definition, fuel consumption can range anywhere from zero to the maximum potential capacity of the equipment; therefore, staff believes that missing fuel consumption data must be filled with values that can either be correlated with other measured operational parameters or be based on the actual fuel use values under usual operating conditions. Staff prescribes data substitution procedures for load-based units (units producing electrical and/or thermal output that are equipped with data handling system that can automatically match up output data with fuel use data) and non-load-based units. After reviewing Part 75 procedures for load-based units (USEPA Part 75), and finding that these procedures are likely to produce reasonably accurate estimates, staff decided to model the proposed procedure after the Part 75 rule, with modifications to suit

California's applications. For non-load-based units, staff applied a similar tiered concept as Part 75 and created 4 tiers of data substitution, requiring the operator to use a best available estimate consistent with the U.S. EPA Part 98 if data capture rate is greater than 95%, and use the 90th or 95th percentile value of fuel use rates in the facility's records if data capture rate is below 95% or 90% (but greater than 80%), respectively. In section 95103, the revised rule requires the facility operator to periodically monitor the proper functioning of fuel measurement device and record fuel use data at least weekly. Such monitoring will form the basis for missing data substitution (see the section on *Enhancements to Monitoring Requirements* in this chapter for a discussion of this requirement). If a unit does not meet the criteria for using either the load-based or the non-load-based procedure, the operator must conservatively substitute missing data using the maximum potential fuel flow rate. However, given that the proposed rule provides the option for facilities to use a best available estimate if facility level fuel consumption can be accurately determined, staff expects that it will be rare for any facility to use the maximum potential fuel flow rate as the last resort.

Alternative Monitoring Plan. In addition, in the interest of balancing the collection of accurate data and creating an incentive to achieve a high data capture rate using a conservative substitution approach, the proposed rule includes provisions to allow operators to submit an alternative interim monitoring plan for ARB's approval in the event of unforeseeable breakdown of equipment that is expected to cause a missing data rate of more than 20%, which is the threshold for an automatic nonconformance. The proposed rule provides guidelines for alternative monitoring plans and also makes allowance for sources reporting using CEMS (Tier 4) to temporarily use a fuel-based calculation method (Tier 2 or Tier 3) if certain criteria are met.

Cumulative Missing Data Elements. To address the situation of having multiple parameters each with less than 20% of missing data, but in combination causing more than 20% of emissions to not be directly accounted for, staff defines the minimum amount of data that must be captured in order to avoid a nonconformance finding as cumulatively 80%. In other words, missing data elements cannot cumulatively cause more than 80% of emissions to not be directly calculated from measure parameters. Otherwise, it is an automatic nonconformance even if the operator has correctly followed all the missing data substitution procedures in the rule. However, a nonconformance does not necessarily prevent a positive verification finding, depending on the contribution of the source to the facility emissions total.

D. Accounting for Biofuel Purchases Used in Stationary Combustion

1. Background

After it was determined that biomass-derived fuels would not be required to have a compliance obligation for their CO_2 emission under the Cap-and-Trade Regulation, it became clear that simple reporting of biogenic emissions would not be rigorous enough for avoiding a compliance obligation. In regards to this issue, staff assessed the following concerns: 1) the motivation to over-report biomass-derived fuels would be high because of the avoided compliance obligation; 2) some biomass-derived fuels, mainly manure digester gas, had the potential for receiving double credit for emissions reductions; once as an offset, and then again as a biomass-derived fuel without a compliance obligation; and 3) there was a need to prevent the simple redirection of biomass-derived fuels from other states to California because of the increased economic incentive, considered in effect to be contract shuffling without real reductions in emissions overall. To address these concerns, staff determined that a system needed to be put in place to protect the integrity of the cap-and-trade program.

2. Basis for Proposal

For the proposed revised regulation, staff held discussions with stakeholders to determine the relevant issues and reviewed a variety of alternatives. As a result of these discussions, staff determined that any system designed to ensure the validity of reported CO_2 emissions from biomass-derived fuels needs to meet several criteria: (1) it needs to protect the integrity of the cap-and-trade program; (2) it needs to be implementable in a short time period; (3) it needs to cover all fuels, even those produced out of state; and (4) it needs to be cost effective. Two main ideas were developed in an attempt to satisfy these criteria. The first was to expand verification to include biomass-derived fuels. The second was to try to create a biomass-derived fuel certification program. Although a certification program similar to the Renewable Energy Certificate under the Renewable Electricity Standard regulation (Title 17, CCR, section 97000 et seq.), with an elevated level of assurance, would be an ideal solution, time constraints prevented the development of this program at this time. An achievable alternative, therefore, was to expand the existing verification program to include specific requirements for verification of biomass-derived fuels. Staff encourages stakeholders to provide comments on the possibility of developing a certification program in the future.

3. Reporting and Verification Requirements and Methods

Expansion of the verification systems to included biomass-based fuels will necessitate minor changes to the reporting process to separate biomass-derived fuels that have a compliance obligation under the Cap-and-Trade Regulation from those that do not. Reporting entities will be required to self-report whether the biomass-derived fuel they are reporting has a compliance obligation or not. During the normal verification process the verification team will also evaluate the accuracy of biomass-derived fuel reporting. There are several criteria the verification team will examine, including:

1. Is the fuel listed as a biofuel without a compliance obligation and does it meet all the requirements in 95851.2 of the Cap-and-Trade Regulation?
2. Was the contract in place before January 1, 2010 or is the fuel coming from increased production in order to avoid contract shuffling?
3. Was the fuel used in any other greenhouse gas reduction system?
4. Can the fuel be tracked from production to reporting entity?

The last question is most critical in the case of biomethane where the fuel may be produced in another state, injected into a common transmission pipeline where it is mixed with natural gas, and never actually delivered to the end-user. The fuel ownership may pass through many hands before it arrives at its final destination. This will necessitate verification at multiple locations. The producer must be verified to determine that the fuel meets all criteria in the regulations and that total production meets or exceeds total sales of biomass-derived fuel. All marketers or middle parties in the chain of custody must also be verified to make sure that their biofuel sales do not exceed their purchases. The responsibility for verification of the biomass-derived fuel falls on the entity avoiding the compliance obligation as listed in section 95852.1 of the Cap-and-Trade Regulation.

There are two drawbacks of this solution. First, it will entail a more extensive verification than a certification program would need in order to maintain the integrity of the cap-and-trade program. Second, this program will not allow uncapped stationary sources that purchase their own biomass-derived fuel to receive credit for that fuel. In the case of natural gas, it is assumed the local distribution company (LDC) will adjust the cost of natural gas to include the cost of complying with the cap-and-trade regulation. Capped entities will not bear this cost because they are responsible for their own natural gas emissions. Uncapped entities, which are not directly responsible for their natural gas emissions, will pay this cost because there is no way to back out the biofuel purchase from the LDC's compliance obligation.

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. Stationary Fuel Combustion Sources

1. Background

Most industrial facilities emitting GHGs have stationary fuel combustion sources. Section 95115 of the proposed regulation specifies the methods for estimating emissions from these sources for all industrial sectors. Stationary fuel combustion includes devices that combust solid, liquid, or gaseous fuels, generally for the purposes of generating steam, producing electricity, providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.

In early 2010 staff had discussions with U.S. EPA staff on the federal reporting requirements for stationary fuel combustion sources, which had not been developed to support cap-and-trade. As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements for stationary combustion at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

For the proposed revised regulation, ARB staff relied on the foundation provided in the U.S. EPA mandatory reporting regulation. Subpart C of the U.S. EPA regulation specifies GHG emissions monitoring and reporting requirements for general stationary fuel combustion emissions sources, including methods for calculating CO_2, CH_4, and N_2O emissions from these sources. U.S. EPA's methods involve a series of tiers, with rigor increasing from Tier 1 through Tier 4. ARB and WCI worked within this structure to develop appropriate limitations to U.S. EPA's specifications by fuel type, focusing on the need to ensure accurate carbon values when fuels are likely to have high carbon variability. This approach to harmonization works because the U.S. EPA rule always allows sources to be estimated using a higher tier. GHG emissions reports that meet the proposed ARB requirements would in most cases also meet the U.S. EPA reporting requirements, avoiding the need to prepare and submit two different reports.

In developing the currently proposed ARB regulation, staff reviewed the U.S. EPA *Technical Support Document for Stationary Fuel Combustion Emissions: Proposed Rule for Mandatory Reporting of Greenhouse Gases* (USEPA TSD C) and the *Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments Volume No.: 15. Subpart C – General Stationary Fuel Combustion Sources* (USEPA Comments C 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) for stationary fuel combustion sources and compared them to the current ARB GHG reporting requirements (ARB MRR 2007). As discussed above, staff also discussed with state and provincial colleagues in the WCI Reporting Committee which U.S. EPA requirement adequately supported data needs for a cap-and-trade program, and where limitations or changes were needed. Stakeholder input via WCI and directly to ARB staff is also reflected in the staff proposal

3. Reporting Requirements and Methods

The proposed ARB reporting requirements for stationary fuel combustion sources use U.S. EPA greenhouse gas emissions reporting requirements, with several limitations or modifications to ensure adequate rigor for a market trading program. The proposal addresses reporting of CO_2, biogenic CO_2, CH_4, and N_2O emissions from combustion sources. Although some modifications were needed to the U.S. EPA baseline requirements, many California facilities are already meeting the modified requirements as part of their current ARB reporting.

Emissions Calculation Methods. The U.S. EPA requirements for estimating stationary fuel combustion emissions are divided into various methods, or Tiers. Tier 1 allows use of default emission factor and fuels data. Tier 2 requires use of high heating value for the fuel, and Tier 3 requires fuel sampling to characterize carbon content. Tier 4 requires the use of continuous emissions monitoring systems (CEMS).

In general, when estimating GHG emissions from the combustion of common standardized fuels, which have limited variability in carbon content, lower-tier methods may be applied, which use either default factors, or require relatively limited fuel testing, depending on the fuel type. This helps to limit the costs and complexity of reporting, while providing good accuracy. For fuels likely to be variable in carbon content, the lower-tier methods would often result in significant underestimation or overestimation of GHG emissions; thus, higher tier methods should be applied.

Coal provides an example. The U.S. EPA regulations allows use of a Tier 2 steam production method to estimate CO_2 emissions in units that produce steam, and the use of default emission factors in units with a maximum rated heat input capacity of 250 mmBtu/hr or less. Staff at ARB and in other WCI jurisdictions believe these provisions would allow significant underestimation or overestimation of CO_2 emissions from coal. The proposed regulation would thus require carbon testing or use of CEMS (Tiers 3 or

4, respectively) when coal is used as a fuel. This requirement would apply to other solid fossil fuels, as well.

Natural gas provides a different example. U.S. EPA proposed in amendments to the regulation published August 11, 2010 to define natural gas very broadly; it could include associated gas at oil production sources and other naturally occurring field gases regardless of carbon content. The ARB staff proposal would retain use of the Tier 2 heating value method for natural gas as provided in the U.S. EPA regulation, but would limit its use to pipeline quality gas as defined in the regulation (970-1100 Btu/scf). Natural gas outside this range would be tested for carbon content if a CEMS is not used to estimate emissions.

As in the current ARB GHG reporting regulation, heating values and carbon content would be provided by the fuel supplier or tested directly by the facility consuming the fuel. When fuel sampling is required, the sampling frequencies specified in the U.S. EPA regulation are retained as sufficient for most stationary combustion sources.

For standardized (mostly liquid) fuels listed in the proposed regulation (a subset of fuels listed in Table C-1 of the U.S. EPA regulation), use of default emission factors is permitted when combusted in units with a maximum rated heat input capacity of 250 mmBtu/hr or less, except where fuel heating value analysis is routinely performed, as stated in the U.S. EPA rule. For *de minimis* sources, the option is provided to use lower-tier methods so reporters are not unnecessarily burdened with collecting analytical data for insignificant emission sources. The *de minimis* method could not be a lower tier than that required by U.S. EPA, however, if reporting of the source to U.S. EPA is required.

The staff proposal includes several other specific limitations to the U.S. EPA requirements, also consistent with the WCI harmonization document:

<u>CEMS CO_2 Monitors</u>. ARB staff and other WCI jurisdictions share a concern that emission factors used to convert oxygen to CO_2 concentrations are questionable for fuels with variable carbon content. As such, the staff proposal includes a requirement to install CO_2 monitors when a new CEMS with a flow monitor is installed. Staff believes that CO_2 monitors are likely to provide improved, reliable emissions data. The proposed revised regulation would not require O_2 CEMS to be retrofitted with CO_2 monitors, but would require that CO_2 monitoring be included annually when Relative Accuracy Test Audits are performed on CEMS systems annually. This additional test at minor incremental cost would help to build a base of data for comparing direct CO_2 monitoring with O_2 to CO_2 conversion.

<u>Source Testing for N_2O and CH_4</u>. An addition was made to the U.S. EPA requirements to allow reporters to measure site-specific facility emissions data for nitrous oxide (N_2O) and methane (CH_4) emissions, and to use the data to estimate emissions for the sources that are tested. Source test data would be used instead of default emission factors for estimating emissions. Emission measurements must be performed in

conformance with a facility source test plan submitted to and approved by ARB. This option is consistent with the current ARB requirements and is also consistent with the WCI harmonization document (WCI HER 2010). The option to use source testing is voluntary; therefore, reporters who prefer to use the other less costly methods within the regulation may do so. Several stakeholders want to retain the option even if it results in different values for federal and state reporting.

Biomass CO_2 Determination. A minor change was made to U.S. EPA requirements that require testing of municipal solid waste to determine the biomass portion of CO_2 emissions, extending the requirement to any other fuel for which the biomass fraction is unknown. Staff believes this is important for the accurate, separate calculations of fossil and biomass emissions.

Refinery Fuel Gas Sampling. The U.S. EPA regulation requires the daily sampling of refinery fuel gas when equipment is in place for daily sampling. Daily sampling has been the practice for most refineries under the current ARB GHG reporting regulation, and the staff proposal would extend it to all refineries. Staff believes this is necessary to accurately quantify emissions from refinery fuel gas, which is a highly variable fuel.

Electricity Generating and Cogeneration Units. In order to meet the requirements of AB 32 and ensure consistency with the WCI, a requirement was added to the proposed revisions to require reporting generating capacity, power generated, thermal output, and other information for electricity generation and cogeneration units.

Natural Gas Providers. Facilities using natural gas would be required to report their provider and customer account number. This will be important later for establishing the compliance obligation for fuel suppliers, if the cap-and-trade program is extended to them as proposed.

Procedures for Missing Data. For general stationary fuel combustion sources, and all emissions calculations, requirements have been added to the proposed regulation that describe how to estimate emissions if required data are missing. These requirements were discussed previously.

Benchmarking Data. For some specific products produced by facilities reporting only under stationary combustion requirements, we propose to collect specified product output data to support benchmarking activities.

B. Cement Production

1. Background

Cement production generated about 5.3 million metric tons of process-related CO_2e emissions in 2008 (ARB CA GHG Inventory for 2000-2008). A slightly smaller amount of GHG emissions were also emitted into the atmosphere that year from fuel combustion to heat the kilns where limestone is calcined to manufacture clinker. Cement plants are among one of the largest consumers of coal in California, combusting over 990,000 short tons of coal in 2008 (ARB GHG Cement 2010). Staff has proposed the continued inclusion of cement manufacturing plants in mandatory reporting due to their contribution to the statewide GHG inventory (approximately 1.8 percent of the total in 2008) (ARB CA GHG Inventory for 2000-2008), their importance as a contributor to emissions worldwide, and their inclusion in the United States Environmental Protection Agency's Mandatory Reporting of Greenhouse Gases regulation (USEPA MRR 2009-2010).

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements for cement production at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the cement industry. Finalized in 2009 after an extensive public process, the U.S. EPA rule contains calculation methodologies that are often very similar (but not identical) to those adopted earlier by ARB after our own public process in 2007. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed U.S. EPA's *Technical Support Document for Process Emissions from Cement* (U.S. EPA TSD H 2009) and the *Response to Public Comments, Subpart H-Cement Production (*U.S. EPA Comments H 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) for cement production and compared them to the current ARB MRR requirements (ARB MRR 2007).

In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program. The federal reporting program includes methodologies to quantify GHG emissions from the cement production process. Staff determined that the U.S. EPA MRR and the current ARB MRR (ARB MRR 2007) utilized equivalent methodologies with some minor differences. Staff attempted to harmonize ARB MRR requirements with the U.S. EPA MRR when the federal requirement met the need for compliance grade emissions estimation under a cap-and-trade program. Differences for process emissions, and the rationale for including or not including them in the proposed ARB MRR, are discussed below. Differences for stationary combustion are discussed in that section of this document.

The federal regulation prescribes certain criteria that, when met, require a cement plant to determine and report GHG emissions according to the Tier 4 methodology (Continuous Emissions Monitoring System or CEMS), rather than allowing the option of utilizing a clinker-based methodology, as permissible under the current ARB MRR. We expect most of California's cement plants to calculate their GHG emissions using the Tier 4 CEMS method.

The U.S. EPA MRR also prescribes a clinker-based methodology, similar to the current ARB MRR's clinker-based methodology, to separately calculate process-related emissions when the CEMS methodology is not required. Staff evaluated the federal requirements and determined they were equivalent and in some cases more rigorous than the current ARB MRR. Staff proposes to follow the U.S. EPA MRR sampling and testing requirements to achieve consistency with the federal program while providing the degree of accuracy required for a cap-and-trade program.

The current ARB MRR requires the cement kiln dust (CKD) emission factor to be calculated when CKD is not recycled to the kiln, using the CKD calcination rate. However, staff concluded that the U.S. EPA MRR method, which utilizes total measured CaO and MgO content to determine the CKD emission factor, is equivalent to the current ARB MRR method, and we propose to follow the federal method.

Also included in the staff proposal are the calculation methods from the U.S. EPA MRR for the determination of total organic carbon (TOC) content in raw materials. Emissions arising from the organic carbon content of raw materials are negligible, and if a cement plant does not utilize the prescribed analytical methodology, the operator may continue to use the prescribed default TOC content value.

In 2008, cement plants reported total fugitive emissions equal to 0.13 percent of their total CO_2e emitted that year (ARB GHG Cement 2010) The U.S. EPA MRR does not require the reporting of fugitive emissions and the proposed cap-and-trade program excludes fugitive emissions from a compliance obligation. As such, staff proposes to follow the federal approach and to not continue to require the reporting of fugitive emissions because of their negligible contribution to overall GHG emissions and their exclusion from the cap-and-trade program.

The current ARB MRR requires cement plants to report two cement efficiency metrics. Although we do not propose to continue the reporting of efficiency metrics, we do propose to continue to collect data currently reported (total CO_2 emissions and the quantity of clicker produced) that will enable the calculation of metrics by ARB. Staff also proposes to require operators to report the annual quantity of clinker substitutes and cement substitutes consumed. This will aid with the calculation of additional efficiency metrics, assisting in benchmarking for the cap-and-trade program.

3. Reporting Requirements and Methods

As described, the proposed regulation for cement production would substantially mirror the U.S. EPA MRR requirements. Under the staff proposal, all California cement plants would be required to report combined process-related and combustion CO_2 emissions from clinker production using the Tier 4 (CEMS) methodology, or separately report combustion emissions and process-related CO_2 emissions from clinker production using the 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, biomass-derived CO_2, N_2O, and CH_4 emissions from fuel combustion, fuel consumption, annual quantity of raw material consumed, and other specified data. Finally, we proposed that cement plants also report supporting data to allow ARB to calculate efficiency metrics.

If the conditions specified in 40 CFR §98.33(b)(4)(ii) or (b)(4)(iii) are met, then the operator must determine CO_2 emissions using the Tier 4 Calculation Methodology. This requirement would replace the methods to calculate process-related and fuel combustion CO_2 emissions separately. To allow ARB to continue to separately estimate combustion emissions, the staff proposal continues to require cement plant operators to report fuel usage information by fuel type, whether or not CEMS are employed. This is consistent with the U.S. EPA MRR.

If not required to follow the Tier 4 methodology or otherwise choosing to report using CEMS, the operator must follow the U.S. EPA MRR's clinker-based method to determine process emissions. This method calculates CO_2 emissions from the quantity and composition of clinker produced, the quantity of CKD not recycled to the kiln during the manufacturing process, and the total organic carbon content of the raw materials consumed.

The clinker emission factor is based on the weight fraction of total CaO and total MgO in clinker. The methodology adopted non-calcined for non-carbonate terminology to reflect the anticipated trend of using calcium and magnesium materials in the kiln feed that provide calcium and magnesium to the clinker without creating carbonate-derived emissions. Non-calcined variables include any calcium or magnesium species in the clinker or CKD that did not undergo calcination and contribute to carbonate-derived emissions.

The CKD emission factor is based on both the non-calcined MgO and CaO content that remains in the CKD not recycled to the kiln. The CKD emission factor must be calculated only when cement plant operators do not recycle CKD back to the kiln. Most California cement plants recycle CKD back to the kiln; these operators would report zero emissions associated with CKD.

For reasons of inventory completeness, cement plants would be required to continue to report process-related emissions from the total organic carbon content in raw materials if CEMS are not utilized. 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 if CEMS are not utilized. Cement plants would estimate stationary fuel combustion emissions using measured high heat value and carbon content depending on fuel type, as discussed in the stationary combustion section of this report.

In addition to reporting total carbon dioxide, methane, and nitrous oxide emissions, cement plant operators must report the annual quantity of clinker produced and the annual quantity of cement and clinker substitute consumed for blending. These data will allow ARB to calculate various efficiency metrics, such as the clinker efficiency metric, and would be required for benchmarking activities.

To fully support ARB programs, some additional modifications to the U.S. EPA MRR requirements were necessary. The primary differences are related to specific data accuracy requirements, the reporting of *de minimis* emissions, and what to do if required fuel use or other data are missing. These changes or limitations are discussed primarily in Sections II and VIII of this report.

C. Electric Power Entities

1. Background

The electricity sector has unique characteristics that are reflected in the staff proposal. The staff proposal is consistent with AB 32 requirements, the current ARB regulation (ARB MRR 2007), the proposed electricity sector protocol recommended jointly by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) included as attachment D in the 2007 staff report (ARB ISOR 2007), and the Western Climate Initiative (WCI) *Final Essential Requirements of Mandatory Reporting* (WCI ERMR 2009). Staff's proposal incorporates the requirement in AB 32 and the WCI Partner jurisdictions' recommendation that emissions from electricity generated outside the WCI Partner jurisdictions but consumed within them be included in the program (WCI Program Design 2010).

Imported electricity accounted for 61 million MT of CO_2e, slightly more than the estimated 55 million MT of CO_2e from in-state electricity generation, as published in the 2008 ARB GHG inventory updated May 12, 2010 (ARB CA GHG Inventory for 2000-2008). Of the total greenhouse gas emissions associated with imported electricity, 43 percent was attributed to facilities outside California that are under contract or ownership obligation to serve California customers (ARB CA GHG Inventory for 2000-2008). The remaining 57 percent was attributed to sources that contribute to the western region power pool.

ARB staff presented preliminary regulatory concepts during the March 23, 2010 public workshop and California stakeholders provided further comments. The WCI Electricity

Team has addressed issues specific to the electricity sector related to the design and implementation of the WCI cap-and-trade program, including reporting requirements. ARB staff continues to participate in WCI Electricity Team discussions to assess policy mechanisms for addressing electricity sector emissions, examine technical issues related to the First Jurisdictional Deliverer (FJD) approach, and research issues related to reliability and electricity market efficiency. The Team has consulted with experts and stakeholders through conference calls, public meetings, and the release of written documents for review and comment. In addition, ARB coordinates an Interagency Electricity Sector Working Group with technical staff and management from the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and ARB. The Interagency Working Group has shared expertise and provided insight on various cap-and-trade program design considerations, including the necessary GHG reporting requirements recommended here to support the program. Taking into consideration this variety of input, and after careful analysis, staff prepared the final regulatory proposal.

2. Basis for Proposal

To provide a fair and equal regulatory approach, the proposed reporting regulation requires electric power entities to report emissions from imported electricity and in-state generation. This supports the point of regulation defined under the ARB cap-and-trade program as the “first deliverer of electricity.” This term means either the owner or operator of an electricity generating facility in California or an electricity importer.

To provide regulatory certainty to electric power entities who receive power generated outside California from federal agencies, the definition of electricity importer clarifies that the Western Area Power Administration (WAPA) and the Bonneville Power Administration (BPA) are subject to the regulatory authority of the ARB under this article. Therefore, the definition of “first deliverer” and “electricity importer” are equivalent to the term “First Jurisdictional Deliverer (FJD)” used in the WCI cap-and-trade program design recommendations (WCI Program Design 2010). The WCI design recommendations provide for maintaining conceptual integrity while acknowledging the need to accommodate the regulatory process in each jurisdiction. The staff proposal has been developed to meet the needs of California’s cap-and-trade program.

ARB is considering additional provisions that would clarify how GHG emissions from specified sources will be reported. To protect the environmental integrity of California’s cap-and-trade program and provide a level playing field between in-state and out-of-state generation, it will be necessary to provide reasonable limitations on resource shuffling for imported electricity. Resource shuffling, in effect, appears to lower GHG emissions associated with electricity imported into California, while having no effect on, or creating an increase in, GHG emissions in the western region. In addition, ARB will need information to determine the extent to which resource shuffling, including shifting investments in existing resources serving the western region bulk system power pool, results in increased, decreased, or no net change in GHG emissions in the western region. Some resource shuffling can be minimized by limiting claims of existing lower-emitting resources and the associated GHG emissions for imported electricity. Some resource shuffling is expected to be outside the regulatory authority of the ARB and will be minimized as ARB links with other jurisdictions in the Western Climate Initiative. In this proposal, accounting conventions for nuclear and large hydroelectric resources—existing, large capacity, fully committed resources—are specified to limit financial incentives to change the resource mix for imported electricity in ways that merely shift GHG emissions from California to other jurisdictions. This provision is consistent with the intent of the current ARB regulation (ARB MRR 2007, ARB ISOR 2007) and the WCI *Final Essential Requirements of Mandatory Reporting* (WCI ERMR 2009).

Renewable energy credits (RECs) cannot be used in GHG reporting. This is consistent with the intent of the California cap-and-trade program and the WCI cap-and-trade program (WCI RECs Accounting 2008, WCI RECs Announcement 2010) to provide a smooth transition to a future federal source-based program. A smooth transition requires that RECs from California renewable energy facilities do not have lesser value than RECs from out-of-state facilities, simply due to GHG attribution from the California cap-and-trade program.

3. Reporting Requirements and Methods

Electric power entities are required to continue reporting imported electricity, exported electricity, and retail sales, as applicable. In this proposed revised regulation, electric power entities will now also report emissions associated with imported and exported electricity, pursuant to the methods provided in the regulation. Reported emissions associated with imported electricity will inform the cap-and-trade program compliance requirement for first deliverers of electricity to hold allowances. Moreover, retail sales data are needed in order to inform the allocation of free allowances for retail providers. Exported electricity is reported for ARB inventory purposes. ARB is continuing to require retail providers to report out-of-state facility ownership share and contracts in order to evaluate whether anticipated decreases in future imported electricity emissions are due to resource shuffling or real emissions reductions in the western regional power system due to California's cap-and-trade program. The proposed revisions include a new requirement that the Western Area Power Administration (WAPA) report pump loads for the Central Valley Project and that the California Department of Water Resources (DWR) continue to report its State Water Project pump loads to support future analysis of GHG implications of water conservation and efficiency measures. Two reporting requirements of the current regulation (ARB MRR 2007) have been removed: (1) out-of-state facilities are no longer required to obtain verification of their emissions data reports, and (2) reporting wholesale electricity purchases and sales from California sources for electricity that is consumed in California is no longer required.

The proposed regulation includes minimum reporting requirements to support the California cap-and-trade program in maintaining the environmental integrity of the cap. For claims of specified sources of imported electricity and associated emissions, electric power entities must register those specified sources with ARB according to the regulation. ARB will calculate and publish emission factors for specified sources, including facilities, units, asset-controlling suppliers, and multi-jurisdictional retail providers. Calculation of emissions is based on primary technology and fuel type, as well as a preferred hierarchy of available data sources. For out-of-state sources, GHG facility or unit reports that meet the requirements of this article may be submitted voluntarily to ARB. For specified facilities or units whose owners or operators do not voluntarily report under this article, but are subject to the U.S. EPA GHG Mandatory Reporting Regulation (USEPA MRR 2009-2010), ARB will accept CO_2e emissions reported to U.S. EPA. For specified facilities or units whose operators are not subject to the U.S. EPA GHG Mandatory Reporting Regulation, including cogeneration systems, ARB will accept CO_2e emissions calculated based on heat of combustion data reported to the Energy Information Administration (EIA 2010).

D. Electricity Generating and Cogeneration Units

1. Background

Currently in California, there are about 195 facilities whose primary sector is classified as electricity generation. In 2008, these electricity generating facilities emitted approximately 51 million metric tons of CO_2e, 13 percent of which are biogenic emissions and 2 percent of which came from geothermal processes. Approximately 86 percent of these emissions are attributed to electricity generating facilities with fossil fuel combustion emissions greater than 25,000 metric tons of CO_2e. Of the 195 facilities, about 30 produced emissions in the range of 10,000 to 25,000 metric tons of CO_2e per year. There are also 44 currently reporting facilities that emitted less than 10,000 tons of CO_2e per year. Data shown are from the ARB summary of GHG emissions reported for 2008 under the mandatory reporting program (ARB GHG Summary 2010).

In addition to pure electricity generation facilities, there are also 58 stand-alone cogeneration facilities producing mechanical or thermal energy and electricity, with capacity greater than 1 MW. In 2008, these cogeneration facilities reported emitting about 12 million metric tons of CO_2e. Approximately 99 percent of these emissions were attributed to facilities with greater than 25,000 tons of CO_2e of emissions (ARB GHG Summary 2010). In addition to these stand-alone cogeneration facilities, there are 102 facilities reporting under other industry sector categories that indicated cogeneration as a secondary sector. The cogeneration emissions from these facilities are accounted for as separate entries in reports submitted under primary sectors that include general stationary combustion, electricity generation, cement plants, petroleum refineries, and hydrogen plants.

Staff proposes the continued inclusion of electricity generating and cogeneration units for GHG reporting under the proposed revised regulation because of the significance of the emissions, the inclusion of the sectors in a proposed California cap-and-trade program, and because the facilities are also required to report under the U.S. EPA MRR (USEPA MRR 2009-2010).

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements for electricity generating and cogeneration units at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the electricity generation and cogeneration units. Finalized in 2009 after an extensive public process, the U.S. EPA rule contains calculation methodologies that are often very similar (but not identical) to those adopted earlier by ARB after our own public process in 2007. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed the U.S. EPA *Technical Support Document for Stationary Fuel Combustion Emissions: Proposed Rule for Mandatory Reporting of Greenhouse Gases* (USEPA TSD C 2009) and the *Response to Public Comments, Subpart D – Electricity Generation* (USEPA Comments D 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) and compared them to the current ARB GHG reporting requirements for the sector (ARB MRR 2007). In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program.

In some cases it was necessary to apply changes or limitations to the U.S. EPA requirements to ensure that our proposed regulation fully meets ARB program needs. Generally, modifications to the U.S. EPA baseline were included to increase the accuracy of reported emissions or to provide additional specifications for when required data were not collected. These changes, which apply to most reporting sectors, are discussed below and in the sections on Calculation Methods for Stationary Combustion and Missing Data Substitution Procedures.

3. Reporting Requirements and Methods

There is a significant change proposed in regulation applicability that affects electricity generation and cogeneration units. The applicable reporting threshold would be raised from 2,500 metric tons CO_2e to 10,000 MT of CO_2e for these units. This relieves about 48 facilities of current emissions reporting requirements.

Beyond applicability, the proposed ARB reporting requirements for electricity generating and cogeneration units are similar to the U.S. EPA greenhouse gas emissions reporting requirements. In general this means that units currently reporting under 40 CFR Part 75 would continue to do so, while operators of other units would estimate emissions using the specified methods for stationary fuel combustion sources referred to in section 95115 of the proposed regulation.

Under this proposal, California cogeneration and electricity generation units would usually calculate GHG emissions as specified in Subparts D and C of the U.S. EPA GHG reporting regulation (USEPA MRR 2009-2010). Units directed by U.S. EPA to Subpart C would report under those requirements as modified by the ARB staff proposal. For variable fuels, higher tiers in the U.S. EPA regulation are specified, consistent with WCI's harmonized requirements (WCI HER 2010), as detailed in Section III.A. of this report. Units reporting to U.S. EPA under Subpart D (like Subpart C) would report biomass and fossil CO_2 separately, even when not required to under Part 75.

Reporting would also be required for CO_2 and CH_4 emissions from geothermal generating units. Geothermal facilities would be required to submit a test plan for review and approval, rather than rely on a default emission factor that often results in inaccurate and non-representative emissions estimates for these facilities. There are unique characteristics for each geothermal reservoir, resulting in broad variation in the greenhouse gas contents of geothermal steam. Geothermal facilities are significant sources of GHGs and proposed for inclusion in reporting because AB 32 requires full coverage of the electricity sector.

Operators of hydrogen fuel cells at facilities otherwise subject to reporting would report on the amounts and types of feedstocks used, but would not be required to calculate emissions due to uncertainties in feedstock carbon content and the relative insignificance of fuel cell emissions.

Basic additional data would be included in emissions data reports, including nameplate capacity, net and gross power generated, and fuel consumption by fuel type. For cogeneration units, additional data would include useful thermal output and supplemental firing information. However, staff has proposed not to continue the current requirement for cogeneration facilities to distribute emissions between electricity and thermal outputs. At this point staff does not believe it is important for facilities to determine this information, which is often difficult for operators and complicated by the many variations in cogeneration facility configuration. It is possible the requirement will be reconsidered in the future if it is needed for allowance allocation or benchmarking purposes.

E. Petroleum Refineries

1. Background

The process of refining crude oil stocks to produce high quality transportation fuels and petrochemical products is a very energy intensive process. Nationwide, U.S. EPA estimates that petroleum refining accounted for about 7 percent of the total U.S. energy consumption in 2007, making the sector the second highest industrial energy consumer (USEPA TSD Y). Similarly, in California the State's 21 petroleum refineries produce about 7 percent of the annual GHG emissions in the state – some 35.5 million metric tons of CO_2e in 2008 (ARB GHG Summary 2010). Because of the size and importance of refinery emissions, ARB included provisions for them to be reported in the regulation approved by the Board in late 2007.

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements for refineries at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the petroleum refining industry. Finalized in 2009 after an extensive public process, the U.S. EPA rule contains calculation methodologies that are often very similar (but not identical) to those adopted earlier by ARB after our own public process in 2007. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed the U.S. EPA *Technical Support Document for the Petroleum Refining Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases* (USEPA TSD Y) and the *Response to Public Comments, Subpart Y – Petroleum Refineries* (USEPA Comments Y 2009). We evaluated the methodologies in the final U.S. EPA rule (USEPA MRR 2009-2010) and compared them to the current ARB GHG reporting requirements for the sector (ARB MRR 2007). In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program. As a result of this harmonization effort, the proposed revised regulation includes several variations from the final EPA rule that were deemed necessary to provide the accuracy and consistency required for a cap-and-trade program.

3. Reporting Requirements and Methods

The U.S. EPA final rule contains GHG calculation methodologies for the refinery related source types and gases show in Table III-1.

Table III-1. Refinery Related Source Types

Source	***CO_2***	***CH_4***	***N_2O***
Stationary Combustion	X	X	X
Flares	X	X	X
Catalytic cracking/Fluid Coking	X	X	X
Fluid coking - flexicoker	X	X	X
Catalytic reforming	X	X	X
Sulfur recovery	X		
Coke calcining	X	X	X
Asphalt blowing	X	X	
Delayed coking		X	
Process vents	X	X	X
Uncontrolled blowdowns		X	
Equipment leaks		X	
Storage tanks		X	

Among the 13 source types in the table above, the available emissions calculation methods for three relatively minor sources are considered to have insufficient rigor for inclusion in a cap-and-trade program. For asphalt blowing, equipment leaks, and storage tanks, staff did not find cost-effective and accurate methods for quantifying emissions. Staff investigated the latest U.S. EPA methodologies in the draft MRR along with industry standard publications such as the 2009 API Compendium (API, 2009). In the case of equipment leaks, for example, while new technology such as high volume samplers may provide accurate data for leaking fugitive components, such measurement techniques are often very costly and time and labor intensive. In addition, once emissions rates for leaking components are determined, reporters would still be faced with the difficult if not impossible task of determining the length of time the leak has occurred in order to calculate an annual emissions estimate suitable for cap-and-trade. While emissions from these three sources would still be reported using the available methods in the U.S. EPA rule, ARB staff has recommended that these emissions not be subject to a compliance obligation under the proposed cap-and-trade program.

For the remaining source types, staff has proposed that the revised regulation include methods as described below. Several of the proposed petroleum refinery emissions methodologies reflect minor modifications to the U.S. EPA MRR that ARB staff and WCI jurisdictions believe are essential to support the rigorous and accurate GHG accounting program needed for market trading. These modifications are consistent with WCI's proposed harmonized requirements (WCI HER 2010) and are discussed below.

CO_2 from Fuel Combustion. Operators would use methodologies that account for the carbon variability of fuels. The regulation permits the use of Tier 1 methods only for *de minimis* emissions and certain standardized fuels (see Stationary Fuel Combustion section of this report). Monitoring, data and records requirements are altered as necessary to align with the selected stationary combustion methods. California refineries are provided until January 1, 2013 to establish equipment and procedures for daily sampling and analysis of refinery fuel gas if not already in place. (The U.S. EPA rule requires daily sampling of refinery fuel gas when equipment is in place, and all but two refineries currently reporting in California have been required to perform daily analyses.)

Calculating CO_2 from Flares. For normal flare operations operators would use the more accurate of two methods provided in the U.S. EPA MRR. For start-up, shutdown and malfunction (SSM) periods during which the operator was unable to measure the parameters required, they must determine the quantity of gas discharged to the flare separately for each SSM period. Engineering calculations and process knowledge are then used to estimate the carbon content of flared gas, as required in the U.S. EPA MRR. Data reporting requirements would also be modified to align with this change.

Calculating CO_2 from FCCUs and Fluid Coking. Operators would not be permitted to apply alternative calculation methods for units under the 10,000 barrels per stream day. The threshold in the U.S. EPA MRR was found to be too high, resulting in too much uncertainty for significant quantities of GHG emissions. This limitation also promotes consistency across the range of refineries in California.

Calculating CH_4 from Delayed Coking Units. The U.S. EPA MRR allows operators to use default values for two parameters: volumetric void fraction of the coking vessel and the average mole fraction of methane in the vessel at the time of depressurization. Under the staff proposal, operators would calculate volumetric void volume and measure the mole fraction of methane in the coking vessel gas twice annually. These changes are designed to generate more accurate and consistent data.

Uncontrolled Blowdown Systems. The U.S. EPA MRR provides two methods for calculating methane emissions from uncontrolled blowdowns: (1) use a default emission factor, or (2) use the process vent emission calculation methodology. The staff proposal would require that operators use the more precise process vent emissions methodology. Data reporting requirements have been modified to align with this change.

Records that Must be Retained. The staff proposal includes language which requires that operators retain data required to demonstrate that process vent emissions do not exceed specified thresholds for methane and carbon dioxide content.

Missing Data Substitution Requirements. The proposed revised regulation refers operators to the missing data substitution procedures for stationary combustion and

CEMS sources in section 95129 of the regulation, while such procedures for separate refinery process emissions are specified in the refineries section of the regulation. In both cases progressively more stringent requirements apply as more data are missing. The data substitution procedures, based on those in U.S. EPA's successful Acid Rain Program, are designed to provide a strong incentive for reporters to generate accurate and complete GHG accounting with as little data substitution as possible.

F. Hydrogen Production

1. Background

Hydrogen plays a central role in the production of clean low sulfur transportation fuels in California. Thirteen of the 21 petroleum refineries in California produce hydrogen on-site, and another six merchant hydrogen plants produce and supply hydrogen to California petroleum refineries (ARB GHG Summary 2010). The production of hydrogen generates large quantities of carbon dioxide derived from the wide variety of hydrocarbon feedstocks that serve as a hydrogen source. Because of the size and importance of hydrogen production emissions, ARB included provisions for them to be reported in the regulation approved by the Board in late 2007.

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements for hydrogen production at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for hydrogen production facilities. Finalized in 2009 after an extensive public process, the U.S. EPA rule contains calculation methodologies that are often very similar (but not identical) to those adopted earlier by ARB after our own public process in 2007. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed the *U.S. EPA Technical Support Document for the Hydrogen Production Sector: Proposed Rule for*

Mandatory Reporting of Greenhouse Gases (USEPA TSD P) and the *Response to Public Comments, Subpart P-- Hydrogen Production* (USEPA Comments P 2009). We evaluated the methodologies in the final U.S. EPA rule (USEPA MRR 2009-2010) and compared them to the current ARB GHG reporting requirements for the sector (ARB MRR 2007). In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program. As a result of this harmonization effort, the proposed revised regulation includes several variations from the final U.S. EPA rule that were deemed necessary to provide the accuracy and consistency required for a cap-and-trade program.

3. Reporting Requirements and Methods

Hydrogen production facilities are required to reporting both stationary combustion and process related GHG emissions. The hydrogen production reporting requirements in the staff proposal reflect several modifications to the U.S. EPA MRR, consistent with the WCI harmonization proposal, as discussed below.

CO_2 from Fuel Combustion. Operators would use methodologies that account for the carbon variability of fuels. The regulation permits the use of Tier 1 methods only for *de minimis* emissions and certain standardized fuels (see Stationary Fuel Combustion section of this report). Monitoring, data and records requirements are altered as necessary to align with the selected stationary combustion methods.

Sampling Frequencies. Because operators use a wide variety of feedstocks, which may often vary in carbon content, the proposal requires daily sampling of most feedstocks and weighting of carbon content values consistent with the prescribed frequency. Monthly sampling would be allowed for pipeline quality natural gas. Monthly testing of composite daily samples would also be permitted for liquid and solid fuels. The regulation provides users with a methodology for determining the monthly weighted feedstock carbon content based on this daily sampling regime.

Data Reporting Requirements. The operator would be required to report the amount of carbon in unconverted feedstock for which GHG emissions are calculated and reported under other requirements in the regulation (e.g., carbon in a flared waste stream). This is essential to preventing the double-counting of a cap-and-trade compliance obligation.

Missing Data Substitution Requirements. The proposed revised regulation refers operators to the missing data substitution procedures for stationary combustion and CEMS sources in section 95129 of the regulation, while such procedures for separate hydrogen production process emissions are specified in the hydrogen production section of the regulation. In both cases, progressively more stringent requirements apply as more data are missing. The data substitution procedures, based on those in U.S. EPA's successful Acid Rain Program, are designed to provide a strong incentive for reporters to generate accurate and complete GHG accounting with as little data substitution as possible.

G. Glass Production

1. Background

Eight of California's thirteen glass production facilities, with individual emissions exceeding 25,000 metric tons of CO_2e, produced just over 550,000 metric tons of combustion-related CO_2e emissions in 2008 (ARB GHG Summary 2010). An additional amount of process-related GHG emissions were emitted into the atmosphere that year from the calcination of carbonate-based raw materials to produce various glass products. However, those emissions were not reported under the current mandatory reporting regulation (ARB MRR 2007), which requires glass production facilities to report according to stationary combustion requirements only.

Staff is proposing to include glass production process emissions in the revised ARB MRR. This would also capture combustion emissions from several facilities currently below reporting thresholds. Glass production facilities are a significant contributor to GHG emissions worldwide, and are included in the United States U.S. EPA MRR (USEPA MRR 2009-2010).

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the glass industry. The U.S. EPA rule was finalized in 2009 after an extensive public process. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed U.S. EPA's *Technical Support Document for the Glass Manufacturing Sector* (U.S. EPA TSD N 2009) and the *Response to Public Comments, Subpart N- Glass Production* (U.S. EPA Comments N 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) for glass production and compared them to the current ARB MRR requirements (ARB MRR 2007).

As mentioned above, current ARB reporting requirements for glass manufacturing requires the reporting of stationary combustion emissions only. The U.S. EPA requirements that we propose to add to California requirements include a method to calculate and report process emissions associated with glass manufacturing. In addition, U.S. EPA MRR incorporates, and the staff proposal includes, methods to more clearly delineate the emissions from fossil and biogenic sources of combustion emissions, and the specific sources of those emissions. These are positive enhancements to collect more complete and accurate GHG emissions and other data from this industrial sector.

In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program. In some cases it was necessary to modify federal requirements to ensure that our proposed regulation fully meets ARB program needs. Generally, modifications to the U.S. EPA regulation were included to increase accuracy or to provide additional specifications for the replacement of missing analytical data. These changes apply to most reporting sectors and are described in the sections on Stationary Fuel Combustion and Missing Data Substitution Procedures.

3. Reporting Requirements and Methods

As described, the proposed regulation for glass manufacturing would substantially mirror the U.S. EPA MRR requirements. Under the staff proposal, all California glass manufacturing plants that surpass the reporting threshold would be required to report combined process-related and combustion CO_2 emissions from the production of glass using the Tier 4 (CEMS) methodology, or separately report combustion emissions and process-related CO_2 emissions from glass production using the raw material input-based method specified in 40 CFR §98.143(b)(2). Glass plants would also be required to report annual CO_2, biomass-derived CO_2, N_2O, and CH_4 emissions from fuel combustion, fuel consumption, the annual quantity of carbonate-based raw materials, the annual quantity of glass product(s) produced, and other specified data.

If certain conditions specified in the federal rule are met (40 CFR §98.33(b)(4)(ii) or (b)(4)(iii)), then the operator must determine CO_2 emissions using the Tier 4 Calculation Methodology. This requirement would replace the methods to separately calculate process-related and fuel combustion CO_2 emissions. To allow ARB to continue to separately estimate combustion emissions, the staff proposal continues to require operators to report fuel usage information by fuel type, whether or not CEMS are employed. This is consistent with the U.S. EPA MRR.

If not required to follow the Tier 4 methodology or otherwise choosing to report using CEMS, the operator must follow the U.S. EPA MRR's glass raw material input-based method to calculate process emissions. This method calculates CO_2 emissions from the glass furnace based on the amount of each type of carbonate-based raw material charged to the furnace, the mass fraction of the carbonate-based mineral in each type of carbonate-based raw material consumed, the specified emission factor for each type of carbonate-based raw material consumed, and the fraction of calcination achieved for each type of carbonate-based material consumed.

The final proposal would require glass manufacturing plants to calculate fuel combustion CO_2, biomass-derived CO_2, N_2O, and CH_4 emissions based on the quantity and type of fuel burned annually if CEMS are not utilized. Glass plants would estimate stationary fuel combustion emissions using measured high heat value or carbon content depending on fuel type, as discussed in the stationary combustion section of this report.

To fully support ARB programs, some additional modifications to the U.S. EPA MRR requirements were necessary. We propose to collect some additional annual glass product output data to support benchmarking activities. Additional differences are related to specific data accuracy requirements, the reporting of *de minimis* emissions, and what to do if required fuel use or other data are missing. These changes or limitations are discussed elsewhere in this report.

H. Lime Manufacturing

1. Background

Lime manufacturing in California resulted in just over 25,000 metric tons of combustion-related CO_2e emissions in 2008 (ARB GHG Summary 2010). A slightly larger amount of process-related GHG emissions were emitted into the atmosphere that year from limestone calcination to produce lime. However, those emissions were not reported under the current mandatory reporting regulation (ARB MRR 2007), as under the current regulation lime manufacturers are required only to report stationary combustion emissions.

Staff has proposed the inclusion of lime manufacturing process emissions as well as combustion emissions in the revised regulation. Lime manufacturing is a significant contributor to GHG emissions worldwide (U.S. EPA TSD S 2009), and is included in the U.S. EPA MRR (USEPA MRR 2009-2010).

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the lime industry. The U.S. EPA rule was finalized in 2009 after an extensive public process. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed *U.S. EPA's Technical Support Document for the Lime Manufacturing Sector* (U.S. EPA TSD S 2009) and the *Response to Public Comments, Subpart S- Lime Manufacturing* (U.S. EPA Comments S 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) for lime production and compared them to the current ARB MRR requirements (ARB MRR 2007).

The existing ARB reporting requirements for lime manufacturing require the reporting of stationary combustion emissions only. The U.S. EPA requirements which we propose to adopt include methods to more clearly delineate the emissions from fossil fuel and biogenic sources of combustion emissions, and the specific sources of those emissions. In addition, U.S. EPA incorporates a method to compute and report process emissions associated with lime manufacturing. These are positive enhancements to collect more complete and accurate GHG emissions and other data from this industrial sector.

In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program. In some cases, it was necessary to modify federal requirements to ensure that our proposed regulation fully meets ARB program needs. Generally, modifications to the U.S. EPA MRR were included to increase accuracy or to provide additional specifications for when required data were not collected. These changes, which apply to most reporting sectors, are described in the sections on Stationary Fuel Combustion and Missing Data Substitution.

3. Reporting Requirements and Methods

As described, the proposed regulation for lime manufacturing would substantially mirror the U.S. EPA MRR requirements. Under the staff proposal, California's lime manufacturing plant would be required to report combined process-related and combustion CO_2 emissions from the production of lime, calcined lime byproduct/waste that was sold, and calcined lime byproduct/waste that was not sold by using the Tier 4 (CEMS) methodology, or separately report combustion emissions and process-related CO_2 emissions from lime products and byproducts using the lime-based method specified in 40 CFR §98.193(b)(2). Lime plants would also be required to report annual CO_2, biomass-derived CO_2, N_2O, and CH_4 emissions from fuel combustion, fuel consumption, the quantity of raw materials consumed, the quantity of lime product produced, the quantity of lime by product/waste that was sold and was not sold, and other specified data.

If the conditions specified in 40 CFR §98.33(b)(4)(ii) or (b)(4)(iii) are met, then the operator must determine CO_2 emissions using the Tier 4 Calculation Methodology. This requirement would replace the methods to separately calculate process-related and fuel combustion CO_2 emissions. To allow ARB to continue to separately estimate combustion emissions, the staff proposal continues to require lime plant operators to report fuel usage information by fuel type, whether or not CEMS are employed. This is consistent with the U.S. EPA MRR.

If not required to follow the Tier 4 methodology or otherwise choosing to report using CEMS, the operator must follow the U.S. EPA MRR's lime-based method to calculate process emissions. This method calculates process CO_2 emissions from the quantity of lime and calcined lime product/waste produced during the manufacturing process, the CaO and MgO content of each type of material, and the specified stoichiometric ratios.

Three total emissions factors must be determined, one for each type of lime produced, calcined lime byproduct/ waste that was sold, and calcined lime byproduct/ waste that was not sold. Each emission factor is based on the specified stoichiometric ratio and the chemical composition (percent total CaO and MgO) of each type of lime and each type of calcined byproduct/waste that was sold or not sold.

The final proposal would require lime manufacturing plants to calculate fuel combustion CO_2, biomass-derived CO_2, N_2O, and CH_4 emissions based on the quantity and type of fuel burned annually if CEMS are not utilized. Lime plants would estimate stationary fuel combustion emissions using measured high heat value or carbon content depending on fuel type, as discussed in the stationary combustion section of this report.

To fully support ARB programs, some additional modifications to the U.S. EPA MRR requirements were necessary. The primary differences are related to specific data accuracy requirements, the reporting of *de minimis* emissions, and what to do if required fuel use or other data are missing. These changes or limitations are discussed elsewhere in this report.

I. Nitric Acid Production

1. Background

Two facilities in California produce nitric acid, which is commonly used to manufacture nitrogen-based fertilizer and explosives (U.S. EPA TSD V 2009). The production pathway begins with the stepwise catalytic oxidation of ammonia, followed by a series of additional chemical reactions to ultimately make nitric acid (U.S. EPA TSD V 2009). Greenhouse gas emissions reporting was not triggered for either facility by the current ARB regulation because their combustion emissions, which were negligible, did not surpass the 25,000 metric tons of CO_2e reporting threshold (ARB GHG Summary 2010). The current regulation does not include reporting requirements for the principal source of GHG emissions at nitric acid production facilities - nitrous oxide (N_2O) process emissions (ARB MRR 2007).

Staff has proposed the inclusion of nitric acid production facilities in the ARB MRR to capture their nitrous oxide process emissions. Nitrous oxide has a global warming potential of 310 metric tons of CO_2 equivalent emissions per metric ton of N_2O, making it a very potent greenhouse gas (U.S. EPA TSD V 2009). Nitric acid production facilities are required to report under the U.S. EPA MRR (USEPA MRR 2009-2010).

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for nitric acid producers. The U.S. EPA rule was finalized in 2009 after an extensive public process. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed U.S. EPA's *Technical Support Document for the Nitric Acid Production Sector* (U.S. EPA TSD V 2009) and the *Response to Public Comments, Subpart V- Nitric Acid Production* (U.S. EPA Comments V 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) for nitric acid production and compared them to the current ARB MRR requirements (ARB MRR 2007).

The existing ARB reporting requirements for nitric acid production facilities require the reporting of stationary combustion emissions only, as opposed to process emissions, if they surpass the 25,000 MT of CO_2e reporting threshold. In California, they do not (ARB GHG Summary 2010. The U.S. EPA MRR requirements that we propose to adopt incorporate a method to compute and report process emissions associated with nitric acid production. These are positive enhancements to collect more complete and accurate GHG emissions and other data from this industrial sector.

In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program. In some cases, it was necessary to modify federal requirements to ensure that our proposed regulation fully meets ARB program needs. Generally, modifications to the U.S. EPA baseline were included to increase stringency or to provide additional specifications for when required data were not collected. These changes, which apply to most reporting sectors, are described in the sections on Missing Data Substitution Procedures and Calculation Methods for Stationary Combustion.

3. Reporting Requirements and Methods

As described, the proposed regulation for nitric acid production would substantially mirror the U.S. EPA MRR requirements. Under the staff proposal, all California nitric acid production facilities would be required to report process-related N_2O emissions, as well as any combustion emissions from the production of nitric acid. Combustion emissions would be reported according to the specified methods, including CO_2, biomass-derived CO_2, N_2O, and CH_4 emissions and fuel consumption. Nitrous oxide process emissions would be reported using a site-specific emissions factor and production rate data, or the operator may request approval from ARB's Executive Officer to use an alternative method, such as the use of N_2O CEMS, for determining nitrous oxide emissions. (This parallels a similar process involving the U.S. EPA administrator.) Annual nitric acid production data and other specified data would also be reported.

If not requesting and receiving approval to use an alternative method, the operator must determine the nitrous oxide emissions using the specified method. To determine the nitrous oxide emission factor, an annual performance test must be conducted. Such a test requires the operator to measure (using the specified methods) the nitrous oxide emissions from the absorber tail gas vent for each nitric acid train, the nitrous oxide concentration, and the nitric acid production rate. If applicable, the destruction efficiency and the abatement factor for each nitrous oxide abatement technology must be determined according to the specified methods.

The final proposal would require nitric acid production facilities to calculate fuel combustion CO_2, biomass-derived CO_2, N_2O, and CH_4 emissions based on the quantity and type of fuel burned annually. These facilities would estimate stationary fuel combustion emissions using measured high heat value and carbon content depending on fuel type, as discussed in the stationary combustion section of this report.

To fully support ARB programs, some additional modifications to the U.S. EPA MRR requirements were necessary. The primary differences are related to specific data accuracy requirements, the reporting of *de minimis* emissions, and what to do if required fuel use or other data are missing. These changes or limitations are discussed elsewhere in this report.

J. Pulp and Paper Manufacturing

1. Background

In California, pulp and paper manufacturing facilities generated about 800,000 metric tons of CO_2 emissions in 2008, from combustion emissions only. Combustion emissions from each of the five California pulp and paper facilities ranged from about 65,000 to about 300,000 metric tons of CO_2e per year (ARB GHG Summary 2010). Staff proposes the continued inclusion of pulp and paper manufacturing for GHG reporting under the proposed ARB MRR because of the significance of these emissions, the inclusion of the pulp and paper facilities in a proposed California cap-and-trade program, and because the facilities are also required to report under the U.S. EPA MRR (USEPA MRR 2009-2010).

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements at a public workshop, and received comments at the workshop and thereafter. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the pulp and paper industry. The U.S. EPA rule was finalized in 2009 after an extensive public process. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the proposed revised ARB regulation, staff reviewed *U.S. EPA's Technical Support Document for the Pulp and Paper Sector* (USEPA TSD AA 2009) and the *Response to Public Comment, Subpart AA – Pulp and Paper Manufacturing* (USEPA Comments AA 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) for pulp and paper manufacturing and compared them to the current ARB GHG reporting requirements (ARB MRR 2007). In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program.

The current ARB reporting requirements for pulp and paper manufacturing require reporting of general combustion emissions only. The U.S. EPA requirements, which we propose to adopt, add methods to more clearly delineate the emissions from fossil fuel and biogenic sources of combustion emissions, and the specific sources of those emissions. In addition, U.S. EPA adds a method to compute and report process emissions from the use of makeup chemicals. The inclusion of these process emissions is a key difference between the current and proposed ARB reporting regulations. Because pulp and paper facilities must already collect and report all of the data needed to comply with the federal requirements, ARB's adoption of the more comprehensive U.S. EPA requirements should not impose a major new burden on California facilities.

In some cases, however, it was necessary to modify the U.S. EPA requirements to ensure that our proposed regulation fully meets ARB program needs. Generally, modifications to the U.S. EPA baseline were included to increase the accuracy of reported emissions or to provide additional specifications for what to do when failures occur in data collection. These changes, which apply to most reporting sectors, are discussed below and in the sections on Calculation Methods for Stationary Combustion and Missing Data Substitution Procedures.

3. Reporting Requirements and Methods

As mentioned, the proposed ARB reporting requirements for pulp and paper manufacturing substantially mirror the U.S. EPA greenhouse gas emissions reporting requirements. This includes reporting CO_2, biogenic CO_2, CH_4, and N_2O emissions from general combustion sources, biomass fired combustion units, chemical recovery furnaces/combustion units, and pulp mill lime kilns. Pulp and paper facilities would also be required to report CO_2 process emissions from makeup chemicals, quantities and characteristics of fuels used, spent liquor solids combusted, quantities of $NaCO_3$ and $CaCO_3$ used, annual production, and other data.

Under this proposal, California pulp and paper manufacturing facilities would calculate GHG emissions as specified in Subpart AA of the U.S. EPA MRR (USEPA MRR 2009-2010) and comply with each of the calculation methods and reporting requirements identified, with specific modifications. In particular, while Subpart AA allows pulp and paper facilities to calculate and report combustion emissions using default emission factors for any type of fuel, the staff proposal would require them to follow method selection by fuel type as required of other industrial facilities. This would provide sufficient accuracy to support inclusion of these facilities in a cap-and-trade program, and equitable treatment across industry types.

The method selection for stationary combustion sources is explained in the Stationary Fuel Combustion section of this report, and was developed in close consultation with representatives of other jurisdictions through the WCI Reporting Committee. For standardized homogenous fuels, lower tiers may be used, which allow use of default values to estimate emissions. For more variable fuels, higher tier requirements are specified, which may require fuel sampling and testing or use of a CEMS to ensure that the emissions are estimated accurately.

To fully support ARB programs, some additional modifications to the U.S.EPA MRR requirements were necessary. The primary differences are related to specific data accuracy requirements, the reporting of *de minimis* emissions, and what to do if required fuel use or other data are missing. These changes or limitations are discussed elsewhere in this report. We also propose to collect some specified product output data to support benchmarking activities.

K. Iron and Steel Production

1. Background

Five iron and steel facilities in California are currently subject to GHG reporting under the existing ARB regulation. Under the proposed regulation, each of these facilities would continue to report their stationary fuel combustion emissions, which ranged from just over 25,000 metric tons to about 165,000 metric tons CO_2 in 2008 (ARB GHG Summary 2010). However, facilities with certain operations, such as the use of an electric arc furnace, are subject to additional requirements to report process emissions under the U.S. EPA mandatory reporting final rule (USEPA MRR 2009-2010). One facility in California uses an electric arc furnace, and under the staff proposal would also report these emissions to ARB.

Most of the other “steel” facilities in the state purchase steel slabs from outside suppliers and use these slabs to manufacture rolled steel and other products. Because these other facilities are only heating the slabs, they are subject only to reporting their stationary combustion emissions, as required by section 95115 of the proposed revised regulation and explained in the Stationary Fuel Combustion section of this report.

As discussed in Section I, ARB staff also participated in extensive discussions with the other Western Climate Initiative (WCI) jurisdictions through the WCI Reporting Committee, to identify changes or limitations to U.S. EPA MRR requirements that would result in compliance grade emissions calculations for cap-and-trade while minimizing any need to report different numbers than those reported to U.S. EPA. In March 2010, ARB staff presented current thinking on proposed requirements at a public workshop, and received comments at the workshop and thereafter. Following this, informal stakeholder meetings and phone calls were held to discuss the regulation revisions pertinent to the iron and steel industry. Stakeholder comments on the WCI harmonization proposal (WCI HER 2010) were also reviewed by ARB and discussed with stakeholders and other state representatives on the WCI Reporting Committee. Taking into consideration this variety of input, staff prepared the final regulatory proposal.

2. Basis for Proposal

The staff proposal incorporates the U.S. EPA final reporting rule as the foundation for reporting requirements for the iron and steel industry. The U.S. EPA rule was finalized in 2009 after an extensive public process. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements.

In developing the currently proposed ARB regulation, staff reviewed *U.S. EPA's Technical Support Document for the Iron and Steel Sector* (USEPA TSD Q 2009) and the *Response to Public Comments, Subpart Q – Iron and Steel Production* (USEPA Comments Q 2009). We evaluated the adopted federal GHG reporting requirements and methodologies (USEPA MRR 2009-2010) and compared them to the current ARB GHG reporting requirements for the sector (ARB MRR 2007). In addition, staff discussed with state and provincial colleagues in the WCI Reporting Committee whether each harmonized requirement adequately supported data needs for a cap-and-trade program.

The current ARB reporting requirements for iron and steel production require reporting of general combustion emissions only. The U.S. EPA requirements that we propose to adopt would add methods to compute CO_2 process emissions from specified activities. These are positive enhancements to collect more complete and accurate GHG emissions and other data from iron and steel industry.

In some cases it was necessary to modify the baseline U.S. EPA requirements to ensure that our proposed regulation fully meets ARB program needs. Generally, modifications to the U.S. EPA baseline were included to increase accuracy or to provide additional specifications for when required data were not collected. These changes, which apply to most reporting sectors, are discussed below and in the sections on Stationary Fuel Combustion and Missing Data Substitution Procedures.

3. Reporting Requirements and Methods

As mentioned, the proposed ARB reporting requirements for iron and steel production substantially mirror the U.S. EPA greenhouse gas emissions reporting requirements. In addition to reporting of stationary fuel combustion emissions facilities would report specified process emissions from any taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, electric arc furnace (EAF), argon-oxygen decarburization vessel, or direct reduction furnace.

However, because iron and steel facilities must already collect and report all of the data needed to comply with the federal requirements, the ARB adoption of the more comprehensive U.S. EPA requirements should not impose an additional burden on California facilities.

Under this proposal, California iron and steel production facilities would calculate GHG process emissions as specified in Subpart Q of the U.S. EPA MRR (USEPA MRR 2009-2010), unless already captured through use of a CEMS under Tier 4 of the stationary combustion requirements. Operators would comply with each of the calculation methods and reporting requirements identified in references to the U.S. EPA regulation in sections 95115 and 95120 of the proposed revised regulation, including annual production quantity, fuel use, fuel characteristics, and other data.

To fully support ARB programs, some additional modifications to the U.S. EPA MRR requirements were necessary. The primary differences are related to specific data accuracy requirements, the reporting of *de minimis* emissions, and what to do if required fuel use or other data are missing. These changes or limitations are discussed elsewhere in this report. We also propose to collect some specified product output data to support benchmarking activities.

L. Suppliers of Transportation Fuels

1. Background

Transportation fuel combustion generated about 150 million metric tons of CO_2e emissions in 2008 (CA BOE 2010a, CA BOE 2010b). Staff has proposed the inclusion of transportation fuels in mandatory GHG reporting due to their very sizable contribution to the statewide GHG inventory (approximately 36 percent of the total) (ARB GHG Inventory 2010), their importance as a contributor to emissions worldwide, and their inclusion in the U.S. EPA's final rule on mandatory GHG reporting (USEPA MRR 2009-2010). The current ARB rule does not require the reporting of these emissions (ARB MRR 2007).

In an attempt to minimize the duplication of reporting effort, staff began in early 2010 to review the feasibility of aligning the needed ARB reporting requirements for the transportation fuels sector with the U.S. EPA MRR requirements for suppliers of petroleum products. Staff reached out to potential stakeholders in the fuels industry to determine whether harmonization was feasible and practicable, and if so, what changes to the U.S. EPA MRR may be needed to support the reporting needed for a cap-and-trade program. To date the WCI has not proposed Essential Requirements for transportation fuels reporting, due to expected variations in available points of regulation and the WCI program design's postponement until 2015 of including these fuels in cap-and trade. ARB is proposing to begin transportation fuels reporting beginning in 2012, so that any reporting issues can be resolved well ahead of including this significant new source category in a cap-and-trade program.

Staff presented preliminary regulatory concepts during the March 23, 2010 public workshop, and reviewed public comments submitted at the workshop and thereafter. Taking into consideration this input staff prepared a final regulatory proposal that starts with U.S. EPA requirements, but makes several significant changes to support the cap-and-trade program in California and WCI.

2. Basis for Proposal

The staff proposal begins with the U.S. EPA requirement that suppliers of petroleum products report quantities of emissions due to downstream combustion or use of the products supplied. Our interest for reporting to support cap-and-trade is more narrow, however, and includes only emissions from transportation fuels (not all petroleum products), and only those used in California (not those exported). Due to the need to limit transportation fuel emissions to the combustion of such fuels inside the California border, it was not possible to align directly with the U.S. EPA MRR. By harmonizing instead with the California Board of Equalization motor vehicle fuel and diesel fuel tax return process, we were able to meet the “within-California” limitation while simplifying the reporting process and reducing overall costs. GHG reports that meet the proposed ARB requirements would not meet the U.S. EPA reporting requirements, however; some entities would be required to submit different State and federal reports.

In developing the currently proposed ARB regulation, staff reviewed U.S. EPA’s *Technical Support Document: Subpart MM Product Definitions and Default Emission Factors* (USEPA TSD MM 2009a), *Technical Support Document: Industry Overview of Suppliers of Petroleum Products (*USEPA TSD MM 2009b) and the *Response to Comments Document: Subpart MM — Suppliers of Petroleum Products* (USEPA Comments MRR 2009). Staff determined that the U.S. EPA MRR required modifications to: (1) only account for transportation fuels combusted within the borders of California; (2) account for emissions from biodiesel and biodiesel blends; (3) account for emissions from liquefied petroleum gas (LPG) produced at refineries; and (4) account for CH_4, N_2O, and CO_2 from biomass-derived fuels. These differences and the rationale for separate requirements are discussed below.

The first factor that made complete harmonization with the U.S. EPA MRR most difficult was the fact that we wanted to separately capture only fuels combusted within California. In the U.S. EPA MRR, the reporter is the fuel refiner. After consultation with refiners and other industry stakeholders, staff determined the refinery is not a workable point of regulation for purposes of fuel supplier reporting for cap-and-trade for most of the fuel delivered, since refineries are often not aware of the final destination of fuels they produce. After consultation with position holders and California Board of Equalization (BOE) staff we determined that BOE already requires reporting for taxation purposes of most of the needed data, including volumes of fuel imported below the terminal rack and delivered across the rack (CA BOE 2010c). We consulted with position holders and enterers (the majority of which are subsidiaries of or related to companies that own or are related to refineries), and determined that emissions reporting would not be a significant additional burden for them. Therefore, we chose position holders at the terminal rack and enterers importing below the rack as appropriate reporters for the proposed revised regulation. In order to account for all fuel combustion in California, refiners are still required to report deliveries to entities that are not licensed by the California Board of Equalization as fuel suppliers. Refiners currently report this information to BOE. ARB staff will continue to evaluate the concept of position holders relative to railroads and other specific types of fueling operations and may propose modifications to the regulations as appropriate.

We also determined that our verification needs and requirements made reporting at the refinery impractical. At refineries, verifiers would be required to verify conformance for many additional fuel measurement devices to meet the accuracy requirements of the regulation, whereas if the position holder’s fuel volume across the rack is used, verifiers could trust that reported volumes are accurate because they are custody transfer points used for commercial billing and taxation purposes, and because all fuel-dispensing devices at terminal racks are sealed by the local weights and measures authority attesting to their accuracy.

Biofuels have no specific reporting requirements in the U.S. EPA MRR. However, ARB staff has determined that transportation biofuels production and import information is important so that an accurate accounting of all transportation fuel emissions can be obtained. Biofuels production and imports are already accounted for under the ARB Low Carbon Fuel Standard (LCSF) (Title 17, *California Code of Regulations*, section 95480 *et seq.*). Staff propose to require reporting by biofuel producers and importers under the ARB MRR only if they do not report the required information under LCFS reporting.

Under the U.S. EPA MRR, refiners are required to report emissions individually from all the components of natural gas liquids (NGL). For cap-and-trade, liquefied petroleum gas (LPG) would hold a compliance obligation, so refiners would be required to report LPG emissions. As a subset of NGL, LPG would require only minor additional reporting. LPG emissions would be reported as the sum of its component emissions.

3. Reporting Requirements and Methods

The federal regulation prescribes certain criteria that, when met, allow suppliers of petroleum products to determine and report CO_2 and CO_2 from biomass-derived fuels according to a modified Tier 1 methodology (simply, Volume * Default Emission Factor). Due to the highly regulated and consistent nature of transportation fuels, the use of the modified Tier 1 methodology by suppliers of transportation fuels should provide the accuracy required for cap-and-trade. CH_4 and N_2O emissions (not required by the U.S. EPA MRR) would also be reported using a Tier 1 methodology, using the default high heat values and default emission factors allowed for stationary fuel combustion sources under Subpart C of the U.S. EPA MRR. The addition of CH_4, N_2O, and CO_2 from biomass-derived fuels is required for consistency with other sectors and the desire to capture CO_2e while tracking biogenic emissions separately.

Thus, the proposed regulation for suppliers of transportation fuels would specify calculation methods from the U.S. EPA MRR, but these methods would be used by other reporters. Under the staff proposal, all California position holders, enterers and refiners would be required to report CO_2, biomass-derived CO_2, CH_4, and N_2O from the eventual combustion of transportation fuels in California; refiners would report these emissions from LPG. Emissions would be calculated using a Tier 1 or modified Tier 1 methodology from the U.S. EPA MRR. Biofuel producers and importers would be required to report only if not already reporting under the LCFS.

Position holders, enterers, refiners, and biofuel producers would be required to report the volume (in barrels) of each component of the finished fuel by type, grade and season that is listed in U.S. EPA MRR tables M-1 and M-2, for fuel delivered across the rack, imported, supplied or produced, that will be combusted or oxidized in California. Refiners are required to report the volume of LPG, as well as the volumes of each individual component of LPG, that will be combusted or oxidized in the state of California.

M. Suppliers of Natural Gas, Natural Gas Liquids, and Liquefied Petroleum Gas

1. Background

Natural gas combustion by core customers generated approximately 40 million metric tons of CO_2e emissions in 2008 (CGEU 2009), while liquefied petroleum gas (LPG) combustion generated approximately 7 million metric tons of CO_2e emissions in the same year (ARB GHG Inventory 2000-2008). Staff has proposed the inclusion of natural gas and LPG suppliers in mandatory reporting due to their contribution to the statewide GHG inventory (approximately 10 percent of the total), their importance as a contributor to emissions worldwide, and their inclusion in the U.S. EPA's final rule on mandatory GHG reporting (USEPA MRR 2009-2010). The current ARB rule does not require the reporting of these emissions (ARB MRR 2007).

In an attempt to minimize the duplication of reporting effort, staff began in early 2010 to review the feasibility of aligning the needed ARB reporting requirements for the suppliers of natural gas and LPG with the U.S. EPA MRR requirements for natural gas and natural gas liquid (NGL) products. Staff reached out to potential stakeholders in this industry to determine whether harmonization was feasible and practicable, and if so, what changes to the U.S. EPA MRR may be needed to support the reporting needed for a cap-and-trade program. To date the WCI has not proposed Essential Requirements for natural gas and NGL reporting, due to expected variations in available points of regulation and the program design's postponement until 2015 of including these fuels in cap-and trade. ARB is proposing to begin natural gas and LPG reporting beginning in 2012, so that any reporting issues can be resolved well ahead of including this significant new source category in a cap-and-trade program.

Staff presented preliminary regulatory concepts during the March 23, 2010 public workshop, and reviewed public comments submitted at the workshop and thereafter. Taking into consideration this input, staff prepared a final regulatory proposal that uses U.S. EPA requirements with minor changes to support the cap-and-trade program.

2. Basis for Proposal

The staff proposal begins with the U.S. EPA requirement that suppliers of natural gas and NGLs report quantities of emissions due to downstream combustion or use of the products supplied. Our interest for reporting to support cap-and-trade is more narrow, however, and only includes emissions from natural gas and certain NGLs used in California. Due to this limitation, the desire to avoid double counting of natural gas usage by large industrial users exceeding the 25,000 metric ton CO_2e threshold, the desire to capture all natural gas combusted in the state, and the desire to include LPG combusted in California, it was not possible to fully harmonize with the U.S. EPA MRR. GHG reports that meet the proposed ARB requirements would not exactly meet the U.S. EPA reporting requirements; at least minor modifications of the reports would be needed for some entities.

In developing the currently proposed ARB regulation, staff reviewed U.S. EPA's *Technical Support Document: Suppliers of Natural Gas and Natural Gas Liquids* (USEPA TSD NN 2009), and the *Response to Comments Document: Subpart NN — Suppliers of Natural Gas and Natural Gas Liquids* (USEPA Comments NN 2009). Staff determined that the proposed ARB MRR would require modifications from the U.S. EPA MRR requirements in order to (1) support a different accounting mechanism for subtracting out natural gas supplied to large industrial users above the 25,000 metric ton CO_2e threshold from the local distribution companies' (LDC) reported emissions; (2) account for emissions from LPG produced by NGL fractionators and combusted within the borders of California; (3) account for emissions from LPG imported into the state; and (4) account for CH_4, N_2O, and biomass-based CO_2 emissions. These differences in reporting requirements and their rationale for including or for not including them in the proposed revised regulation are discussed below.

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The first factor that made complete harmonization with the U.S. EPA MRR difficult was the accounting methodologies employed in the federal MRR to subtract large industrial natural gas users' emissions from an LDC's reported emissions. The methodology employed by U.S. EPA could lead to double counting in instances where the large industrial user's consumption of natural gas was below 460,000 million standard cubic feet, yet its reported emissions were above 25,000 metric tons of CO_2e due to additional fuel combustion or process emissions. In order to avoid this situation, for reports under the revised ARB MRR, LDCs would report emissions without subtracting out large industrial users. ARB would then subtract the natural gas emissions from large industrial users above the 25,000 metric ton CO_2e threshold prior to calculating the compliance obligation.

Additionally, LDCs that are public utility gas corporations (PUGCs) may define the city gate as the state border for the purposes of calculating emissions from natural gas. This would result in PUGCs calculating a mass balance around their system where the total reported emissions are based on what comes in (1) at the state border; (2) from interconnects with other LDCs and intra- and interstate pipelines; (3) from in-state natural gas production; and (4) from storage, minus what goes out to interconnects with other LDCs and intra- and interstate pipelines and storage. LDCs would also have to report monthly fuel volumes and weighted average HHVs for all their wholesale customers to facilitate verification of the wholesale customers' emissions.

Complete harmonization is also prevented by the fact that NGL fractionators would only be required to calculate emissions on LPG combusted in California. The U.S. EPA MRR requires NGL fractionators to report the annual volume of odorized propane delivered to others.

Additional requirements different from those in the U.S. EPA MRR are needed due to California LPG importers and inter- and intrastate pipelines not having reporting requirements under the U.S. EPA MRR. LPG importers into the U.S. are currently required to report under the U.S. EPA MRR Subpart MM (petroleum products), and some of these U.S. imports would also be reported under the transportation fuels section of the proposed ARB MRR. But the requirement for LPG importers into California to report the volume of LPG imported, as well as its constituents if the composition is supplied to the importer, would be added. And in order to capture all natural gas emissions, intrastate pipelines would have to report as if they were a LDC, and interstate pipelines would be required to provide customer information including monthly natural gas volumes and weighted average HHV for all of their customers in California.

3. Reporting Requirements and Methods

The federal regulation prescribes certain criteria that, when met, require suppliers of natural gas liquids to determine and report emissions of CO_2 according to either a Tier 1 (Volume * Default High Heat Value* Default Emission Factor) or a modified Tier 1 (Volume * Default Emission Factor) methodology. For LPG, we also believe that the use of a Tier 1 or modified Tier 1 methodology is appropriate. For NGL fractionators that are required to report and calculate emissions based on the actual composition of the LPG and LPG consignees (importers to California) that are required to calculate emissions based on composition when available, the use of the lower tiers does not compromise accuracy due to the use of compositional data. The default LPG factors from Table C-1 used by consignees that do not have composition data is a conservative value that is within 5% of the values of commonly sold fuels in California.

The federal regulation also prescribes certain criteria that, when met, require local distribution companies to determine and report CO_2 emissions according to methodologies which ARB is requiring to be implemented as Tier 2 (Volume * Annual Average High Heat Value * Default Emission Factor) or modified Tier 2 (Volume * Annual Average Emission Factor). ARB staff believe that due to the highly regulated nature of pipeline natural gas the use of the Tier 2, with reporter specific high heat values (HHV), or a modified Tier 2 methodology, with a reporter specific emission factor for natural gas suppliers consisting of the reporter specific HHV and the default natural gas emission factor, should provide the accuracy required for cap and trade. If the gas is outside the range of 970-1,100, the local distribution company will be required to use a Tier 3 (carbon content) methodology when calculating emissions. The addition of CH_4, N_2O, and CO_2 from biomass-derived fuels is required for consistency with other sectors and the desire to capture CO_2e while tracking biogenic emissions separately.

The proposed regulation for suppliers of natural gas, natural gas liquids and liquefied petroleum gas would use the methods of the U.S. EPA MRR. Under the staff proposal, all California local distribution companies, intrastate pipelines, interstate pipelines, NGL fractionators, and LPG importers would be required to report combustion $CO_{2,}$ CH_4 , N_2O, and biomass-based CO_2 emissions from the complete combustion of the fuels, using a Tier 1 or modified Tier 1 methodology from the U.S. EPA MRR.

LDCs, which consist of both public utility gas corporations and publicly-owned natural gas utilities, and intrastate pipelines would be required to report the volume of natural gas delivered to all users in California using the mass balance approach described above. Deliveries to large industrial and wholesale customers would be subtracted before calculating the compliance obligation. PUGCs would report monthly wholesale volumes and weighted average HHV for all wholesale customers. Interstate pipelines would be required to report the fuel consumption of all their California customers, so that a complete accounting of natural gas in California can be obtained.

NGL fractionators would be required to report the volume of LPG supplied to end users in California as the sum of the individual components, and LPG consignees who import LPG into California would be required to report the volume of LPG imported and supplied to end users in California as the sum of the individual components if the composition is known, or the total volume of LPG imported if the composition is not known.

N. Suppliers of Carbon Dioxide

1. Background

There is a wide variety of applications for captured CO_2 in the economy, and it is expected that processes such as carbon capture and sequestration will grow in the future. As a result of stakeholder input, ARB staff included provisions in the current reporting regulation (ARB MRR 2007) that provided petroleum refiners and hydrogen producers the option to report transferred CO_2. Year 2008 reporting data indicates that seven California petroleum refineries reported a total of 650,000 metric tons of captured and transferred CO_2. On average this represented 3.1 percent of these facilities' total CO_2 emissions (ARB GHG Summary 2010).

2. Basis for Proposal

The U.S. EPA final rule (UEPA MRR 2009) includes a general reporting requirement for all producers of CO_2, and importers and exporters of more than 25,000 MT CO_2e from CO_2, N_2O and fluorinated GHGs, to report as suppliers of carbon dioxide. U.S. EPA also requires suppliers of carbon dioxide to report the amount of CO_2 sold for thirteen applications, such as food and beverages and enhanced oil and natural gas recovery, if known.

ARB staff evaluated the U.S. EPA requirements and concluded that reporting methods were sufficiently rigorous for a cap-and-trade program, with the exception of missing data procedures. By aligning with the wording of the U.S. EPA regulation as we develop requirements suitable for cap-and-trade, we are able to reduce duplication of effort, questions of interpretation, costs, and complexity for reporters. In most cases, GHG reports that meet the proposed ARB requirements would also meet U.S. EPA reporting requirements. The U.S. EPA MRR reporting requirements for suppliers of carbon dioxide are included in the proposed revised regulation, with two general modifications.

3. Reporting Requirements and Methods

The U.S. EPA final rule requires CO_2 suppliers to report the amount (mass) of CO_2 captured from production units, captured from production wells, and imported to and exported from the United States. Producers estimate mass from flow meter readings, and importers/exporters from bulk containers, prior to purification, processing or compressing. Reporting requirements exclude CO_2 that may be imported or exported in equipment such as fire extinguishers.

The ARB staff proposal would require these same reporters to additionally specify the mass of imports to and exports from California. ARB staff expects to use this data in the assessment of a cap-and-trade compliance obligation limited to California usage, similar to fuel suppliers.

In addition, ARB staff reviewed the missing data substitution procedures in the U.S. EPA final rule and found them to be inadequate to support market trading. The proposed revised regulation specifies separate missing data substitution procedures for reporting to ARB. Progressively more stringent requirements apply as more data are missing. The data substitution procedures, based on those in U.S. EPA's successful Acid Rain Program, are designed to provide a strong incentive for reporters to generate accurate and complete GHG accounting with as little data substitution as possible.

O. Petroleum and Natural Gas Systems

1. Background

The current ARB mandatory GHG reporting regulation requires producers of crude oil and natural gas to report all stationary combustion emissions at facilities with 25,000 metric tons or more of CO_2e (ARB MRR 2007). For 2008, California's oil and gas producers reported about 6.9 million metric tons of CO_2e from combustion (ARB GHG Summary 2010). In the Initial Statement of Reasons for the 2007 regulatory proposal, staff acknowledged some significant sources at these facilities were not covered by the proposed regulation: "...additional reporting requirements will be developed in the future for process and fugitive emissions from oil and gas exploration, production, processing, transmission and distribution" (ARB MRR ISOR 2007).

ARB began to address this shortcoming in the following year, contributing staff expertise and a portion of the funding to develop an "Oil and Gas Exploration and Production and Natural Gas Gathering and Processing Greenhouse Gas Accounting Protocol," initially drafted under the auspices of the Western Regional Air Partnership (WRAP), and ultimately published by The Climate Registry (TCR O&G 2010). In 2009, WRAP handed off the development of essential reporting requirements that could support inclusion of petroleum and natural gas combustion and process sources in a cap-and-trade program to the WCI. A Technical Working Group (TWG) with industry representatives, regulatory parties, trade and environmental groups, and U.S. EPA representation provided valuable knowledge and assistance to WRAP, WCI and TCR throughout this period in meetings, conference calls, and through extensive written comments.

In 2009, WCI formed an Oil and Gas Subcommittee among member jurisdictions, which, with TWG input, developed a series of eight Issue Papers that were circulated for public comment in March 2010 (WCI O&G IP 2010). The Issue Papers contain draft recommendations for quantifying emissions for significant source categories in the upstream oil and gas sector, and served as the basis for WCI input to U.S. EPA as the agency developed federal reporting requirements for the sector. WCI also hosted an Oil and Gas Collaborative Meeting, held November 2009 in Santa Fe, providing the WCI Partners an opportunity to meet with interested stakeholders so that the partners could increase their understanding of the oil and gas sector and receive input directly on emissions reporting issues and emissions reduction opportunities.

2. Basis of Proposal

U.S. EPA issued a proposed rule for GHG reporting for Petroleum and Natural Gas Systems in April 2010, and intends to finalize its proposal this fall. Like the adopted reporting rule for other sectors, the U.S. EPA proposal was not written to support a cap-and-trade program. Nonetheless, as part of the ARB and broader WCI effort to harmonize with the U.S. EPA reporting regulation as much as possible, the ARB staff proposal is built around the U.S. EPA proposed Petroleum and Natural Gas reporting requirements.

Because the U.S. EPA proposal was not final by the time ARB staff had to prepare this regulatory proposal, our proposed requirements for oil and gas are different in format and in length from the requirements for other sectors. ARB's proposed requirements for oil and gas systems include complete rule language, rather than references to adopted federal rule language as in other sectors. This format may change once U.S. EPA finalizes its proposal for oil-and-gas systems, as we consider other changes following public comment on the substance of the ARB staff proposal.

In developing the proposed revised ARB MRR, staff reviewed the U.S. EPA *Technical Support Document for Fugitive Emissions Reporting from the Petroleum and Natural Gas Industry* (USEPA TSD W 2009). We also reviewed the Issue Papers discussed above (WCI O&G IP 2010), and the comments submitted by stakeholders in response to the issue papers. Staff discussed with state and provincial colleagues in the WCI Reporting Committee and the WCI Oil and Gas Subcommittee whether each proposed U.S. EPA requirement would adequately support the data needs for a cap-and-trade program. The WCI Partners commented officially on the proposed U.S. EPA reporting rule for oil and gas systems in June 2010, offering recommendations that would improve the rigor and accuracy of reporting for some source categories sufficiently to include them in the region's cap-and-trade program (WCI O&G 2010). ARB staff reviewed these recommendations, and presented preliminary thinking on inclusion of this sector in the mandatory reporting public workshop on March 23, 2010, and reviewed public comments submitted at the workshop and thereafter. Taking into consideration this variety of input, and after careful analysis, staff prepared a final regulatory proposal. It includes several modifications to proposed U.S. EPA language where it was felt that more rigorous methodologies were required to ensure the accuracy needed to support a cap-and-trade program.

3. Reporting Requirements and Methods

U.S. EPA chose source types primarily based on the significance of their contribution to the U.S. GHG inventory (USEPA TSD W 2009). WRAP and WCI identified similar sources in their work. Based on the proposed Subpart W and WCI harmonization efforts, the proposed revised regulation would include reporting for the oil and gas production sector source types shown in Table III-2.

Table III-2. Oil and Gas Production Sector Source Types

Source Type	*CO_2*	*CH_4*	*N_2O*	*Reporting only*	*High Un-certainty*
NG pneumatic high bleed devices and pumps	x	x			
NG pneumatic low bleed devices	x	x			
Dehydrator vent stacks	x	x			
Well venting and unloading	x	x			x
Gas well venting – unconventional well completions and workovers	x	x			x
Gas well venting – conventional well completions and workovers	x	x			x
Blowdown vent stacks	x	x			
Onshore production and processing storage tanks	x	x			x
Well testing and flaring	x	x			
Associated gas venting and flaring	x	x			
Flare stacks	x	x	x		x
Centrifugal compressor wet seal degassing vents	x	x			x
Reciprocating compressor rod packing venting	x	x			
Leak detection and leaker emission factors	x	x		x	
Population count and emission factors	x	x		x	
Offshore petroleum and natural gas production	x	x	x	x	
EOR injection pump blowdown	x				
Produced water dissolved CO_2	x				
Portable equipment combustion	x	x	x		

For the sources above designated as “reporting only,” the WRAP/WCI process concluded that available methodologies would not produce accurate enough data to support cap-and-trade. Additional sources were identified by U.S. EPA for which current emissions inventories are highly uncertain and may be significantly underestimated (USEPA TSD W 2009).

The sections proposed for Subarticle 5 of the staff proposal, Petroleum and Natural Gas Systems, are discussed in detail below.

Section 95150: Definition of the Source Category.
The Petroleum and Natural Gas Systems source category consists of the following industry segments. Each segment is defined in detail in the proposed regulation, consistent with U.S. EPA Subpart W.

1. Offshore petroleum and natural gas production
2. Onshore petroleum and natural gas production
3. Onshore natural gas processing plants
4. Onshore natural gas transmission compression
5. Underground natural gas storage
6. Liquefied natural gas (LNG) storage
7. LNG import and export equipment
8. Natural gas distribution

Section 95151: Reporting Entity and Threshold.
Facilities within any of the eight industry segments listed above would be required to report emissions when annual emissions equal or exceed 10,000 MT CO_2e. In the case of onshore petroleum and natural gas production, the reporting footprint under the U.S. EPA proposed Subpart W has been defined as the hydrocarbon basin as determined by the American Association of Petroleum Geologists (1991). The staff proposal incorporates the U.S. EPA approach, albeit with the 10,000 MT threshold. The reporting entity for onshore production is the operating entity listed on the state well drilling permit, or the state operating permit for wells where no drilling permit is issued by the state; section 95151(a)(1) of the proposed revised regulation adds further specification from the preamble of proposed Subpart W.

For a single facility or a reporting entity covering multiple facilities, the emissions from portable equipment would be included in determining whether emissions exceed the threshold. The proposed U.S. EPA Subpart W requires operators to include combustion emissions from portable equipment that resides at a wellhead for more than 30 days in a reporting year. This 30 day minimum residence time limitation has not been included in the proposed revised ARB MRR. This is to ensure that potentially significant portable equipment emissions in this source category are accounted for (and avoid situations where portable equipment could be shifted among facilities to avoid emissions reporting).

Section 95152: GHGs to Report.
This section specifies the source types subject to reporting for each of the industry segments in section 95150. Note that operators would also report stationary combustion emissions following the requirements of section 95115 of the proposed regulation, and the quantities of CO_2 that are captured and transferred offsite as specified in section 95123 of the proposed regulation. Those requirements are discussed elsewhere in this report.

Section 95153: Calculating GHG emissions.
The three U.S. EPA Subpart W sections 98.233(a), (b) and (c) have been modified, consolidated and are included in this proposed rule as Sections 95153(a) and (b). U.S. EPA's proposed Subpart W allows operators to use manufacturer-derived natural gas bleed rates to calculate emissions from all pneumatic high and low bleed devices and pneumatic pumps. This approach was not deemed to be of sufficient rigor for a cap-and-trade program by the WCI Oil and Gas Subcommittee. Thus, this proposed regulation contains a requirement to measure natural gas consumption for high bleed pneumatic devices and pneumatic pumps. This requirement is phased in over a two year period to provide operators with time and flexibility to meter these gas releases.

Section 95153(a), Natural gas pneumatic high bleed device and pneumatic pump venting. Operators would be required to install metering of natural gas venting on 50 percent of all high bleed devices and pneumatic pumps by January 1, 2013. Manufacturer-derived data would be used to estimate emissions for all unmetered high bleed and pneumatic pumps. By January 1, 2014, all natural gas venting by high bleed devices and pneumatic pumps would be metered. For metered devices and pumps, GHG volumetric and mass emissions (CO_2 and CH_4) would be calculated using the metered volumetric natural release and gas composition data. For unmetered devices and pumps, manufacturer-derived emissions are multiplied by device operational time to calculate annual volumetric natural gas emissions, which are then converted to GHG emissions using gas composition data.

Section 95153(b), Natural gas pneumatic low bleed device venting. The U.S. EPA proposed method has been retained in the case of all low bleed pneumatic devices. The OEM bleed rate data is multiplied by device operation time to calculate natural gas volumetric emissions. GHG emissions are then calculated using natural gas composition data.

Section 95153(c), Acid gas removal (AGR) vent stacks. The proposed U.S. EPA methodology requires operators to calculate annual CO_2 emissions based on either continuous gas analyzer data or quarterly gas analysis of gas entering and exiting an AGR unit. A mass balance equation is then used to calculate emissions.

The proposed revised ARB MRR would require increased sampling frequency (monthly) and use of a volume weighted CO_2 content in cases where a continuous gas analyzer is not installed. This requirement was deemed necessary to provide compliance grade data for cap-and-trade. A provision was added to exempt emissions reporting in cases where AGR unit vent stack emissions are captured and then re-injected into the oil/gas field.

Section 95153(d), Dehydrator vent stacks. U.S. EPA's proposed Subpart W contains two dehydrator emissions calculation methods: Method (1) for absorbent based dehydrators, and Method (2) for desiccant based dehydrators. The ARB staff proposal includes both of these methods with minor modifications. For absorbent based dehydration, operators must use the simulation software GRI-GLYCalc to calculate CH_4

and CO_2 emissions. For desiccant based dehydrators, operators must calculate emissions based on the volume and pressure of the desiccant vessel, the percent of desiccant vessel void volume, the number of fillings, and gas composition. The original U.S. EPA equation in proposed Subpart W (Eq. W-5) was modified slightly to provide a more workable formula. Instead of using the variable T (time between refilling in days) which may vary, emissions for each refilling are calculated and summed. This minor change should provide a more accurate emissions estimate without increasing the reporting burden.

Section 95153(e), Well venting for liquids unloading. The proposed U.S. EPA Subpart W rule allows operators to choose one of two emissions calculation methods. The proposed regulation requires that operators use the more rigorous Calculation Methodology 2. The operator must calculate emissions from each well venting for liquids unloading. Calculation Methodology 2 contains two terms – the first calculates emissions resulting when the well is depressurized, while the second term derives emissions during the time period that the well remains depressurized and flowing during the liquids unloading procedure. This methodology will generate more accurate and consistent data.

Section 95153(f), Gas well venting during unconventional well completions and workovers. Unconventional wells are defined as wells where hydraulic fracturing procedures have been employed to enhance gas production volumes. Currently, well “fracking” is not practiced in the State of California. This reporting methodology has been included in the proposed revised ARB MRR and is unchanged from the proposed U.S. EPA Subpart W.

Section 95153(g), Gas well venting during conventional well completions and workovers. This proposed rule adopts the proposed U.S. EPA Subpart W methodology without changes. Operators are required to calculate emissions from each gas well venting episode during conventional well completions and workovers.

Section 95153(h), Blowdown vent stacks. This proposed rule adopts the proposed U.S. EPA Subpart W methodology without changes. Operators are required to calculate the total volume of gas vented, correct this volume to standard temperature and pressure, and calculate CH_4 and CO_2 emissions based on the composition of the vented gas and number of venting events.

Section 95153(i), Onshore production and processing tanks. The proposed revised regulation would modify U.S. EPA’s proposed Subpart W reporting requirements for storage tanks, to require the use of a more accurate methodology for storage tanks where the oil production rate is 10 barrels per day or greater. This change was necessary to produce more accurate data suitable for cap-and-trade. For storage tanks where the oil production rate is less than 10 barrels per day, operators may use the E&P Tanks software package to calculate CH_4 and CO_2 emissions as proposed in Subpart W. For those storage tanks where oil production is 10 barrels per day or greater, operators must annually determine the gas-oil ratio (GOR) of produced liquids.

Emissions are then calculated based on GOR and the oil production rate at the storage tank battery.   Additional sampling is required if one or more producing wells are connected to or disconnected from the storage tank. This calculation methodology is based on the assumption that all the gas generated during the determination of GOR is ultimately liberated both in the storage tank and during the crude oil stabilization process.

For transmission storage tanks, the calculation methodology proposed in U.S. EPA Subpart W is not included in the proposed rule. In the Technical Support Document for this sector, U.S. EPA states, "the volume of condensate is typically low in comparison to the volumes of hydrocarbon liquids stored in the upstream segments of the industry. Hence the emissions from condensate itself in the transmission segment are insignificant." (USEPA TSD W 2009). It appears that U.S. EPA has required that operators screen transmission storage tanks to determine if emissions are occurring as a result of a stuck scrubber dump value. If emissions are detected, operators must then measure tank emissions volume and gas composition to determine GHG emissions. In comments to U.S. EPA, WCI recommended that this reporting methodology not be included. This potential emission source might better be addressed by implementation of direct emissions control regulations at the State jurisdictional level.

<u>Section 95153(j), Well testing venting and flaring</u>. The methodology proposed in U.S. EPA Subpart W has been included in the staff proposal with minor modifications. Operators are required to sample and measure GOR. This minor change was made to promote data consistency.

<u>Section 95153(k), Associated gas venting and flaring</u>. The methodology proposed in U.S. EPA Subpart W has been included in the staff proposal with minor modifications. As was the case with well testing venting and flaring, operators are required to sample and measure gas-oil ratio (GOR). This minor change was made to promote data consistency.

<u>Section 95153(l), Flare stacks</u>. The U.S. EPA proposed Subpart W methodology has been adopted with minor modifications. Equation W-14 has been modified to correct errors. Additionally, the value of η (flare destruction efficiency) has been modified in the case of pass-through CO_2 where η has been set to equal 0, rather than 1.

<u>Section 95153(m), Centrifugal compressor wet seal degassing vents</u>. The staff proposal would include this methodology from the proposed U.S. EPA Subpart W without modification.

<u>Section 95153(n), Reciprocating compressor rod packing venting</u>.   This methodology from the proposed U.S. EPA Subpart W has been included in the ARB staff proposal without modification.

<u>Section 95153(o), Leak detection and leaker emission factors</u>. This methodology from the proposed U.S. EPA Subpart W has been included in the ARB staff proposal without

modification. While screening of equipment leaks provides operators with valuable qualitative information concerning which components are leaking, accurate facility-wide quantification of leaks is not practical using this methodology, and the emissions estimates would not provide compliance grade data for a cap-and-trade program.

Section 95153(p), Population count and emissions factors. This methodology from the proposed U.S. EPA Subpart W has been included in the ARB staff proposal without modification. This semi-quantitative approach will help operators focus mitigation efforts. However, a methodology using population counts and use of generic emissions factors would not provide compliance grade data for a cap-and-trade program.

Section 95153(q), Offshore petroleum and natural gas production facilities. This methodology from the proposed U.S. EPA Subpart W has been included in the ARB staff proposal without modification. California offshore facilities have not been previously been required to report GHG emission under the MMS GOAD program. Thus this reporting requirement will provide ARB with preliminary data that will help to evaluate the importance of offshore oil and gas production related emissions. This approach, however, would not provide compliance grade data for a cap-and-trade program.

Section 95153(r), Volumetric emissions. This section establishes methods for converting natural gas volumetric emission measurements made at ambient conditions to standard conditions. It is included in the staff proposal without change from the proposed U.S. EPA Subpart W language.

Section 95153(s), GHG Volumetric emissions. This section establishes methods for converting natural gas volumetric emissions to GHG volumetric emissions using the mole percent composition (CH_4 or CO_2) of the natural gas. It is included in the staff proposal without change from the proposed U.S. EPA Subpart W language.

Section 95153(t), GHG mass emissions. This section establishes methods for converting GHG volumetric emissions to GHG mass emissions using the gas density (CH_4 or CO_2). For the staff proposal, Equation W-23 of proposed U.S. EPA Subpart W was modified by removing the GWP term, as this reporting rule requires that operators report GHG emissions (CH_4 or CO_2) in terms of metric tons for each gas rather than metric tons of CO_2e.

Section 95153(u), EOR injection pump blowdown. This section establishes reporting requirements for the blowdown of pumps associated with Enhanced Oil Recovery (EOR) operations where supercritical phase CO_2 is injected into oil and gas fields to stimulate productivity. Currently, only thermal EOR activities take place in the State of California. This method is included in the revised ARB MRR to ensure that should critical phase CO_2 EOR activities begin in California that there is a method in place to quantify emissions.

Section 95153(v), Produced water dissolved CO_2. This section establishes reporting requirements for dissolved CO_2 in produced water resulting from Enhanced Oil Recovery operations where supercritical phase CO_2 is injected into oil and gas fields to stimulate productivity. Currently, only thermal EOR activities take place in the State of California. This method is included in the reporting regulation to ensure that should critical phase CO_2 EOR activities begin in California that there is a method in place to quantify emissions.

Section 95153(w), Portable equipment combustion emissions. This section requires that operators report combustion emissions from portable equipment which resides at wellheads. This equipment includes (but is not limited to) drilling rigs, dehydrators, compressors, electrical generators, steam boilers and heaters. The limitation contained in the proposed U.S. EPA Subpart W that this equipment must reside at a wellhead for more than 30 days has been eliminated. This change is designed to ensure that all combustion emissions associated with the production of oil and gas are reported.

Section 95154: Monitoring and QA/QC requirements.
This section of the staff proposal is a modification of proposed U.S. EPA Subpart W language to include requirements for additional data that must be collected as a result of the changes in methodology required by section 95123, as described above.

Section 95155: Procedures for estimating missing data.
Complete and accurate data reporting is essential to the success of a market trading program. The data substitution procedures included in this section are designed to provide a strong incentive for reporters to generate accurate and precise accounting of GHGs with as little substitute data as possible.

Section 95156: Data reporting requirements.
This section of the staff proposal is a modification of proposed U.S. EPA Subpart W language, to add several requirements for data that must be reported as a result of the changes in methodology required by section 95123, as described above.

Section 95157: Records that must be retained.
This section of the staff proposal is a modification of proposed U.S. EPA Subpart W language, to add several requirements for records that must be retained in support of the changes in methodology required by section 95123, as described above.

Section 95158: Default Emission Factor Tables.
This section reproduces tables of default emission factors referenced in the regulation text, without change from the tables in proposed U.S. EPA Subpart W.

IV. GREENHOUSE GAS VERIFICATION REQUIREMENTS

A. Background

The core verification requirements outlined in the proposed revised regulation are relatively unchanged from the requirements that exist under the current mandatory reporting regulation (ARB MRR 2007). The existing GHG reporting regulation contains third-party verification requirements for all reporting entities. Independent verification of reported GHGs is expected under international standards (ISO 2006a) and is integral to many existing GHG reporting programs, including The Climate Registry's voluntary program (TCR 2010) and the European Union Emissions Trading Scheme (EU ETS 2007). The Western Climate Initiative (WCI) also requires all participating jurisdictions to adopt regulations that include third-party verification for a regional cap-and-trade program (WCI ERMR 2009). 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. International guidance reports developed by the International Organization for Standardization (ISO) (ISO 2006a) lay out best practices that require third-party verification to address the need for consistency and a high level of confidence in calculating and reporting ton of GHG emissions.

As part of this proposed regulatory action, ARB staff is proposing to continue to use independent third-party verification, consistent with WCI regional program design and international standards. ARB staff is continuing to work with local air quality management districts and air pollution control districts (AQMD/APCDs or local districts) to better define the process that allows local districts to provide verification services. Staff expects to develop proposed regulatory language related to the process for local districts' participation in verification in 15-day changes to the currently proposed regulation. In developing the verification requirements for this proposed revised regulation, staff looked at the existing verification requirements to support mandatory GHG reporting and assessed the need for improved verification requirements to support a cap-and-trade program. Internal staff review and collaboration within WCI identified areas that could be clarified or made more stringent to allow for a more rigorous and transparent verification process.

Proposed changes to the existing verification requirements were presented at a workshop on March 23, 2010. Since the proposed clarifications and new language were minor and meant to improve the verification process, there was little to no stakeholder feedback at the time. As such, staff has included the proposed changes presented at the workshop in this proposed revised regulation.

B. Verification of Emissions Data

Even though core verification requirements in the proposed revised regulation are essentially unchanged from the existing requirements, staff is proposing some minor changes and additions. Staff review found that no significant new requirements are needed to transition verification from supporting a reporting-only program to supporting a cap-and-trade program. One new minor addition includes an equation for how verifiers will assess emissions data reports for material misstatement. This equation is consistent with WCI requirements and is based on financial auditing practices. Experience with the existing reporting program also highlighted a need for a third alternative for verification statements. The proposed regulation includes an option for a qualified positive verification statement. This option allows the verifier to make a positive verification finding where the data in the emissions data report may be free of a material misstatement, but there may be a non-conformance that does not result in a material misstatement. In the existing regulation, any non-conformance, whether or not it resulted in a material misstatement, requires the verifier to provide an adverse verification statement to the reporter.

1. The Verification Cycle

The proposed revised regulation calls for the annual verification of all emissions data reports, except for abbreviated reports of facilities outside the cap-and-trade program (i.e. those emitting between 10,000 and 25,000 metric tons of CO_2e). (These abbreviated reports are still subject to ARB audit.) Reporting entities have the option of undergoing a full verification once during a three year cap-and-trade compliance period, with less intensive verification services during the remaining years. A full verification year requires a site visit, sampling plan, review of the data management system, and data checks. Under less intensive verification requirements, verification activities may be reduced to emissions data checks based on the sampling plan developed in the full year of verification.

In performing GHG emissions verification, there is a distinction between a verification body and a verification team. The verification body is a firm that has the liability for the verification services rendered and employs the lead verifier of the verification team and the lead verifier who acts as the independent reviewer of the verification findings. 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 reporting entity.

2. Verification Activities

There are several key elements of verification as proposed in the revised regulation. For the most part, these elements are already required under the current mandatory reporting regulation. The first element is a mandatory site visit during the full 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 reporting entity's emissions data report is 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 in conformance with the regulation.

The verification team is also required to develop a verification plan. The verification plan provides documentation of planned activities, site visits, and document reviews. This plan would be submitted by the verification body to ARB with a Notice of Verification Services, ten days prior to providing verification services to a reporting entity. The Notice of Verification Services allows 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 requires the checking of 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 data report. 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 (i.e., 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 how many data checks to perform. Ultimately, however, the verification team must be able to state with reasonable assurance that the reported emissions do not contain a material misstatement 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 material misstatement threshold of 5 percent on a CO_2e basis at the facility level is consistent with industry practice. Anything that results in an error greater than 5 percent is considered a material error. If an emissions data report does not contain a material misstatement, then it means any errors found during verification do not cause a greater than 5 percent error in total CO_2e emissions reported by the reporting entity.

During the course of the verification, the verification team is required to maintain an issues log of any findings that may cause a material misstatement or affect 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 statement. Any findings that result in a change of the initial data report submitted to ARB must be documented. This careful documentation allows ARB to audit 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 statement to both the reporting entity and ARB to indicate that the verification team has found no material misstatement in the emissions data report, and that the team finds the report meets the requirements of the regulation. Alternatively, the verification body submits an adverse verification statement indicating that the team has found a material misstatement or is otherwise unable to state that the emissions data report meets the requirements of the regulation. As part of the proposed revisions to the existing regulation, the new, third option for verification teams is a qualified verification statement that indicates a verification team found no material misstatement and that there is a non-conformance that did not result in a material misstatement. When providing the verification statement, 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 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 statement. ARB could use any experts at its disposal to review questions, and both parties would be held to the subsequent ARB decision.

In the event an emissions data report receives an adverse verification statement, the Executive Officer will calculate an emissions level for the reporting entity that forms the basis for its obligation under the cap-and-trade program. The factors and methods used by the Executive Officer will be the same as those used to calculate an assigned emissions level for a reporting entity in the case they had not submitted an emissions data report or failed to get the emissions data report verified by the applicable deadlines.

4. Biomass-Derived Fuels Verification

Emissions from several types of biomass-derived fuels will not be required to hold an obligation in the cap-and-trade program. Reporting entities would be able to report these emissions separately as biomass CO_2 and not be required to hold allowances for these emissions. For the purposes of verification, verifiers must be able to have reasonable assurance that any biomass CO_2 emissions included in an emissions data report are from eligible biomass-derived fuels and that they are actually from a verifiable source and not double counted in another program. Quite often, biomass-derived fuel is injected into a natural gas transmission line located hundreds or thousands of miles from the facility that purchased that fuel. Direct measurement at the facility would therefore not accurately detect if the facility was burning a “packet” of biomass-derived fuel injected into the transmission line many miles away. Currently, there is no certification program for tracking these types of fuels as there is in the Renewable Energy Credit program. As such, ARB verifiers will have to check and verify every entity in the chain of custody from where a biomass-derived fuel is created, sold, and then combusted by a reporting entity subject to cap-and-trade. Verifiers will have to review records for sales to ensure they are real and that no party has “sold” more biomass-derived fuel then they produced or purchased. Any biomass-derived biofuel can not also receive an offset credit in another voluntary or mandatory program and still be an eligible biomass-derived fuel for reporting as biomass CO_2 that would not be subject to an obligation in the cap-and-trade program.

In the absence of a biomass-derived certification program, this level of verification is needed to ensure the reporting of biomass CO_2 is accurate, real, and verifiable. These verification requirements could be scaled back if a certification program was developed to track biomass-derived fuel as it was produced, sold, and consumed by various parties in the chain of custody. A possible model for a certification program would be one that would issue a certificate for each unit of biomass-derived fuel and as that fuel was transferred or sold, the certificate authenticating the quality of the fuel as being a biomass-derived fuel would change hands accordingly. This system would have to centrally issue and track every certificate. This type of mechanism would be limited to one certification program to ensure there was no double accounting of the same fuel in multiple programs. The reporting entity would provide the certificates as proof of their purchase and consumption of biomass-derived fuel that is not subject to an obligation. The verifiers could take those certificates at face value of evidence of the type and amount of biomass-derived fuel consumed by the reporting entity. This certificate program could be modeled after the Renewable Energy Credit program.

C. Accreditation of Verifiers

To assure the quality of verification services, staff has proposed retaining the current rigorous accreditation requirements consistent with standards in other existing programs(EU ETS 2007, TCR 2010), as well as ISO guidance (ISO 2006c). 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.

The concept of a verification body having two lead verifiers comes from existing requirements in the European Union (IETA 2005). 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. The Climate Registry and WCI programs have a similar requirement (TCR 2010, WCI ERMR 2009). Moreover, this requirement already forms part of ARB's current reporting requirements (ARB MRR 2007).

1. Lead, General, and Sector Specific Verifiers

ARB currently has about 230 accredited verifiers and 45 accredited verification bodies. These firms and individuals met strict eligibility criteria under the existing regulation, took ARB verifier training, and successfully passed an examination at the end of the training. The total of 230 includes both lead verifiers and general verifiers. These firms and individuals would be able to continue to provide verification services under the proposed regulation once the existing accredited verifiers have attended an ARB training workshop to learn the new reporting requirements under the proposed regulation.

ARB will retain the strict eligibility criteria and training requirements in the existing regulation as the mechanism for new individuals to become verifiers and provide verification services to reporting entities in California.

In addition to general verifiers, ARB recognizes the need for sector specific verifiers for several types of reporting entities, including refineries, transactions reporters, cement, and other manufacturing. These sectors often have complex process emissions, rigorous fuel test requirements, contractual arrangements, and sales and purchase complexities that require verifiers to have special knowledge. ARB currently offers sector specific training in addition to general verification and lead verifier training and this training would be expanded to include new sectors added by the proposed revisions. All lead verifiers and general verifiers may take the additional sector specific training. Based on experience in existing programs, these various requirements aim to ensure quality and consistency in the conduct of verification activities.

2. Accreditation to Support Cap-and-Trade Offset Project Data Report Verification

ARB is also proposing to accredit verifiers to support its compliance offset program. Most of the accreditation requirements for these individuals are the same as those for emissions data report verifiers. However, due to the complexity and variability between different project types, ARB will also require additional project specific experience and training for offset project specific verifiers. All other regulatory requirements for verifiers of offset project data reports are included in the proposed cap-and-trade regulation.

D. Conflict of Interest

ARB's conflict of interest requirements address several types of biases that may occur when a third-party verifier is reviewing an emissions data report. Biases can occur if either a reporting entity or verifier offers inducements when procuring verification services, if there is a financial interest on the part of a member of the verification body in the reporting facility, and because of close relationships between verification bodies and reporting entities that could lead a verification body or verifier to be sympathetic to the interests of the reporting entity. Biases can also occur if a verification body or verifier has provided services that are closely related to the greenhouse gas verification services or those services actually helped in the development of the emissions data report. In this later case, familiarity with a reporting entity's facility could lead the verifier to approach the GHG verification work with a predisposition of the outcome and not truly evaluate the emissions data report with an objective and independent eye.

On a more basic level, when the verification body and reporting entity enter into a contract, they agree on a monetary payment for services rendered. 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 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. The proposed revised regulation contains clarifications and criteria additional to those in the existing mandatory reporting regulation for the potential for conflict of interest assessment between verification bodies and reporting entities.

ARB wants to provide highly accurate GHG data to the public and to support the cap-and-trade program. This requires the verification process to be independent and free of any external bias creeping into the process of reviewing the reported emissions. The conflict of interest requirements are drawn from existing concepts in financial auditing and environmental programs (CEC 2002). 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 potential 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 reporting entity. If potential conflict is found to be low, then ARB will approve the verification and the process will commence. If 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 is 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 proposed revised regulation lists specific tasks that are in conflict with the principle of independent review. Most of these tasks are the same as in the existing regulation.

The regulatory proposal retains the requirement for reporting entities to change verifiers after six years 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 entity. Staff agrees this requirement will reduce complacency that may occur given the comfort and familiarity a verification body may feel toward a reporting entity after that time period. Verifier rotation is currently part of WCI program requirements, and ARB has retained such requirements in the proposed revised 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. Public Resources Code, Section 21080.5 allows public agencies with regulatory programs to prepare a plan or other written document in lieu of an environmental impact report once the Secretary for Resources has determined that the agency meets the criteria for a Certified State Regulatory Program (Title 14, California Code of Regulations (CCR), section 15250). The Secretary for Resources has certified ARB's program for the adoption of regulations (Title 14 CCR section 15251(d)). This certification allows ARB to include an environmental analysis in the Initial Statement of Reasons for the adoption of the regulations, in lieu of preparing an environmental impact report or negative declaration. In addition, ARB will respond in writing to all significant comments that pertain to potential environmental impacts raised by the public during the public review period or at the Board hearing. These responses will be contained in the Final Statement of Reasons for the regulation.

Staff evaluated the potential environmental impacts from the proposed regulation and determined that no significant adverse environmental impacts are likely to result from the proposal. Further, staff has determined that adoption of the proposed regulation will not result in any significant adverse impacts on water quality, land, or biological resources.

This determination was made because the proposed regulation requires only reporting of GHG emissions by specified facilities to ARB, 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.

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). Section 11346.3 of the Government Code requires that, in proposing to adopt or amend any administrative 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.

In this chapter we provide the estimated costs to businesses and public agencies to comply with staff's proposed revisions to the mandatory California greenhouse gas (GHG) reporting requirements. The regulation will affect approximately 750 facilities and other reporting entities in the state (ARB GHG Summary 2010, ARB CEIDARS 2007). Given that various facilities are under common ownership, this equates to approximately 450 businesses (ARB GHG Summary 2010, ARB CEIDARS 2007). While staff has quantified economic impacts to the extent feasible, the cost estimates are necessarily based on approximations of the amount of time required to comply with the regulation, associated labor wage rates, costs of any new required equipment or analysis, and verification costs. 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, depending on various factors such as complexity of operation, facility configuration, types of fuel used, and existing compliance practices. Some facilities may experience an incremental cost increase, while some may experience an incremental cost saving as the results of the proposed revised regulation.

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. For local or State agencies, the proposed rule may result in an incremental cost for some and an incremental saving for others, but statewide, local or State agencies are expected to see a net saving from the proposed rule.

A. Summary of Costs and Economic Impacts

Implementation of the mandatory proposed revised GHG reporting regulation for California has three primary costs: 1) GHG reporting costs, including monitoring, sampling, recordkeeping activities and 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.

In developing the revisions to the GHG reporting regulation, staff has attempted to minimize costs, while complying with the specific reporting requirements of the Act, collecting cap-and-trade quality data, and coordinating with U.S. EPA and Western Climate Initiative (WCI) reporting requirements. Under the proposed regulation, affected businesses and operations include most facilities currently subject to the extant California GHG reporting regulation (ARB MRR 2007), fuel suppliers and electric power entities, several new industrial process emissions categories, new reporting by suppliers of natural gas and transportation fuels, and the reporting of emissions and transactions by electricity importers. In addition, some facilities in the affected industry sectors that emit between 10,000 to 25,000 MT of CO_2e that are not currently subject to reporting, will be required to submit an abbreviated GHG emissions data report under the revised regulation for the purpose of monitoring the integrity of the carbon cap.

The proposed revisions to the regulation will be implemented using existing ARB staffing. In addition, costs are minimized by harmonizing the proposed ARB regulations with existing U.S. EPA reporting regulations (USEPA MRR 2009-2010) and WCI proposals (WCI ERMR 2009 and WCI HER 2010). The majority of facilities subject to the proposed ARB rule are also subject to the U.S. EPA reporting rule. Because of this, the majority of costs for reporters will be incurred in meeting the baseline U.S. EPA requirements, and there will typically only be small incremental costs to meet the additional ARB requirements after the rule revision. The additional incremental cost is due to the need for greater stringency in the ARB requirements to meet the needs of a GHG emissions cap-and-trade program and to provide consistency with the WCI requirements.

A summary of state-wide incremental costs is presented in Table VI-1.

Table VI-1. Summary of State-Wide Incremental Costs (2009 $Million)

Sector	First Year	On-going Year	Total Cost over 10 Years [5]
Privately Owned Utilities [1]	-0.2	-0.2	-2
Manufacturing	2.0	1.4	12
Fuel Suppliers [2]	1.8	1.1	9
Local Government Entities [3]	-0.2	-0.3	-2
State Government Entities [4]	<0.01	-0.01	-0.06
TOTAL	3	2	18

Table Notes:
1. Privately owned utilities include electricity deliverers, electricity generating and cogeneration facilities.
2. Fuel suppliers of petroleum products, biofuels, natural gas, and natural gas liquids.
3. Local government entities affected by the rule include publicly owned utilities, electricity generating and cogeneration facilities, and some general combustion sources at hospitals, prisons, and universities.
4. State government entities affected by the rule include state hospitals, prisons, and universities that operate cogeneration unit and other general combustion sources.
5. A 5% discount rate is applied to the 10-year costs.

For all reporting entities state-wide, we estimate the total annual costs associated with meeting GHG reporting requirements incurred by all affected entities, including businesses, local, and state government, to be $3 million (range of $1 to $8 million) during the first year. The on-going costs for the subsequent years are anticipated to be $2 million (range of $1 to $5 million) annually statewide. The first year costs are higher due to the possible need for training and planning, other start-up costs, and more intensive verification costs to meet the regulatory requirements. The staff anticipates that except for the oil and gas sector, most of the existing reporting entities will already have the necessary equipment and sampling systems in place to support GHG reporting for U.S. EPA and the existing California requirements, and it is not likely that they will need to purchase new equipment to comply with the revised regulation. We anticipate costs to diminish over time as facilities incorporate GHG reporting into their normal business practices. The ranges of the estimated costs are wide because of the substantial variability in potential reporting and verification costs among facilities subject to the regulation.

GHG reporting as specified is mandatory for any facility or entity that meets the regulation's applicability requirements. Therefore, some public agencies are 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 10,000 metric tons of CO_2e from stationary combustion sources or have electricity generation or cogeneration activities. The Department of Water Resources is also expected to have a reporting requirement related to imported power. Most of these facilities are already reporting to ARB under the existing rule, and are expected to see an incremental saving due to significant reduction in reporting requirements in the proposed rule revision. Staff estimates that local agencies will see an overall net saving in the range of $2 million (range of $1 to $3 million) statewide, and state agencies will see an overall net saving of $50,000 (range of $30,000 to $60,000), as a result of the proposed rule revision.

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. Most of the job creation associated with GHG reporting was gained following implementation of the original rule. As part of this revision we are expecting a small additional increase in California employment for technical consultants who will assist facilities in meeting the revised 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, but these are difficult to quantify. At full implementation of the revised regulation, we estimate that approximately 10 to 20 new verifier jobs and no new businesses would be created within California.

All the cost estimates provided in this chapter are relative to the year 2009 (current value of the costs), and all costs are given in 2009 dollars. The information, assumptions and methodologies used to determine compliance costs are summarized in Section C of 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 costs 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. We have determined that the propose regulation is not a major regulation.

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 a part of developing the GHG reporting regulation, we estimated the costs of compliance for facilities subject to the regulation. Briefly, the methodology for estimating costs for facilities and entities included:

- Establishing the baseline for the cost estimation;
- Categorizing affected reporting entities, which include those currently subject to reporting, those newly subject to reporting under the proposed revisions, and those that are no longer subject to reporting under this proposal;
- Identifying the new tasks that each facility type will need to perform to comply with the revised regulation, as well as the existing tasks that each facility type will

no longer need to perform;
- Evaluating the incremental costs associated with the changes in tasks that are expected to be performed by the reporting entities in monitoring and sampling fuel, preparing emissions reports, updating compliance and monitoring plans, developing GHG emission estimates, and providing staff to prepare and submit the emissions reports. The labor costs are calculated by multiplying the estimated time requirements for performing each task by a range of wage rates from the U.S. Bureau of Labor Statistics (BLS 2009);
- Estimating costs for new measurement or monitoring equipment and systems, if any, directly needed to comply with the proposed reporting requirements;
- Estimating the incremental 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;
- Applying the appropriate costs to each facility type to develop overall cost ranges for program implementation;
- Identifying the affected entities operated by local or state government entities and applying the appropriate costs per facility to estimate costs to local and state government; and
- Analyzing costs to small businesses.

The methodology for estimating incremental costs is described in the following subsections.

1. Determining Baseline and Incremental Costs

This analysis focuses on the net difference (or increment) between two cost estimates:

- baseline compliance costs for GHG reporting under extant regulations, and
- compliance costs under the proposed regulatory revisions.

The incremental costs estimated in this analysis do not represent the total costs to comply with GHG reporting regulations, but only the difference between the cost of mandatory GHG reporting with and without the proposed regulatory revisions. The net incremental cost combines both cost increases and cost savings.

Most affected entities —which include industrial facilities, electricity delivery entities, oil and gas entities by geological basins, and suppliers of fuels— will need to meet the U.S. EPA's GHG reporting requirements starting in 2011 (for the 2010 data year) (USEPA MRR 2009-2010). Compliance costs for California's existing GHG reporting rule will continue to be incurred even if the proposed revision is not adopted (ARB MRR 2007, ARB ISOR 2007). Some portions of these costs will be spent to comply with both the U.S. EPA and California requirements simultaneously, while some may be spent to meet only California requirements and some may be spent to meet only U.S. EPA requirements. The compliance costs due to both rules form the baseline costs of this analysis. If ARB adopts the proposed revisions and harmonizes its reporting requirements with those of U.S. EPA, some costs incurred to comply with California's current rule will be eliminated, while some new costs will be added in support of California's proposed cap-and-trade program.

To address these complications with baseline costs, staff has chosen to frame the incremental costs analysis by the compliance tasks that reporting entities are expected to conduct before and after the revised rule becomes effective. The compliance tasks required right before the revised rule becomes effective— regardless of whether the tasks are performed for U.S. EPA only, for California only, or for both programs— are considered the baseline for the incremental cost analysis. Different facility types within the same sector may have different "baseline tasks" depending on the fuels used and the emissions units they have on site. In other words, the baseline and incremental changes are defined from the perspective of the reporting entities, not from the perspective of the ARB rule modifications.

Figure VI-1 illustrates the effects of the two rules in forming the complex baseline of this analysis using a facility that is subject to both the current California rule and the U.S. EPA rule as an example. The generic compliance task list is a representation of a compliance checklist that a facility operator may utilize to manage all the GHG reporting-related requirements. Prior to 2010 and before the U.S. EPA rule became effective, the compliance tasks performed by the reporting entities are entirely attributed to the current California rule. During 2010, the facility continues to report under the current California rule, but many of the existing compliance tasks also meet the data collection requirements of the U.S. EPA rule (though reporting to U.S. EPA does not start until 2011), while new tasks may be added as required by the U.S. EPA. The costs to comply with these rules become intertwined and inseparable for the purpose of establishing a baseline in assessing the costs to revise the California regulation. In 2011, the facility files GHG report with the U.S. EPA for the first time. The operator continues to submit GHG report to ARB under the current California rule, resulting in duplicate efforts in submitting much of the same information to two different agencies. If ARB adopts the revised rule that harmonizes with the U.S. EPA requirements, in 2012 the facility will be relieved from duplicating reporting efforts and will be submitting data only through the U.S. EPA reporting tool, but may report additional data beyond the U.S. EPA requirements to support California's cap-and-trade or other AB 32 mandates.

Using the generic compliance task list in Figure VI-1 as an example, the following compliance tasks become the baseline for the cost analysis: task (No. 1) in the current California rule that is retained in the revised rule, tasks (No. 3 to 6) that meet both the California and U.S. EPA requirements, and tasks (No. 7 to 9) required by U.S. EPA but not required by the current California rule. In the meantime, the task in the current California rule (No. 2) that is not retained in the revised rule becomes an incremental saving, while the new task (No. 10) that is not required by the current California rule nor the U.S. EPA rule becomes an incremental cost. The net change in costs that the facility may see is the sum of the incremental cost and incremental saving from the changes in compliance tasks.

However, not all the affected entities are subject to the current California rule, the U.S. EPA rule, and/or the revised California rule, as in the example above. The effects of the 3 rules and their respective applicability criteria form 5 different baseline scenarios. Tables VI-1a to VI-1e describe these baseline scenarios and provide examples of each. In reality, reporting entities within the same industry sector can fall into different baseline scenarios. Therefore, there is often a one-to-many relationship between industry sector and the baseline scenario. Categorization of industry sectors into more detailed facility types is further discussed in the next subsection.

Figure VI-1. Illustration of Generic Compliance Tasks Due to California and U.S. EPA Regulations in Determining the Baseline for the Cost Analysis

2009	2010	2011
Compliance Task 1 Compliance Task 2 Compliance Task 3 Compliance Task 4 Compliance Task 5 Compliance Task 6	Compliance Task 1 (CA only) Compliance Task 2 (CA only) Compliance Task 3 (both CA & U.S. EPA) Compliance Task 4 (both CA & U.S. EPA) Compliance Task 5 (both CA & U.S. EPA) Compliance Task 6 (both CA & U.S. EPA) Compliance Task 7 (U.S. EPA only) Compliance Task 8 (U.S. EPA only)	Compliance Task 1 (CA only) Compliance Task 2 (CA only) Compliance Task 3 (both CA & U.S. EPA) Compliance Task 4 (both CA & U.S. EPA) Compliance Task 5 (both CA & U.S. EPA) Compliance Task 6 (both CA & U.S. EPA) Compliance Task 7 (U.S. EPA only) Compliance Task 8 (U.S. EPA only) Compliance Task 9: Reporting to U.S. EPA (U.S. EPA only)

Incremental Cost	**2012**
Baseline	Compliance Task 1 (CA only)... ***retain the same requirement***
Incremental saving	~~Compliance Task 2 (CA only)~~ ...***no longer required***
Baseline	Compliance Task 3 (required by U.S. EPA, data used by CA)
Baseline	Compliance Task 4 (required by U.S. EPA, data used by CA)
Baseline	Compliance Task 5 (required by U.S. EPA, data used by CA)
Baseline	Compliance Task 6 (required by U.S. EPA, data used by CA)
Baseline	Compliance Task 7 (required by U.S. EPA, data used by CA)
Baseline	Compliance Task 8 (required by U.S. EPA, data used by CA)
Baseline	Compliance Task 9 (required by U.S. EPA, data used by CA)
Incremental cost	Compliance Task 10 (CA only) ...***new requirement for supporting cap & trade***

Table VI-2a. Regulated entity subject to both the current California rule and U.S. EPA rule (Examples: refineries, cement plants, some industrial facilities with combustion sources, and some power plants and cogeneration plants)

	2009	2010	2011	2012 and beyond
Subjected Rules	Report under the current CA rule.	Report under the current CA rule. Start collecting data for reporting to U.S. EPA for the first time in 2011.	Report under the current CA rule, and report to U.S. EPA for the first time.	Proposed revised rule harmonizes with U.S. EPA rule, with additional requirements to support cap-and-trade.
Cost Attribution	Costs are entirely attributed to the current CA rule.	Some resources spent on sampling and collecting data will be used to comply with both the CA and U.S EPA rules, some may be spent for CA only while some for U.S. EPA only. The resources spent on reporting are attributed to CA only.	Some resources spent on sampling and collecting data will be used to comply with both the CA and U.S EPA rules, some may be spent for CA only while some for U.S. EPA only. Reporting to CA and U.S. EPA separately.	Regulated entities comply with the U.S. EPA rule, but may incur marginal incremental costs to comply with the additional requirements in the revised CA rule or see some cost savings from reduced CA-only requirements. Report to U.S. EPA directly (along with the additional data required by CA only) and no longer need to report to CA separately.

Table VI-2b. Regulated entity subject to the U.S. EPA rule but not the current California rule (Examples: certain facilities in the glass production, lime production, nitric acid production, and fuel supplier sectors)

	2009	2010	2011	2012 and beyond
Subjected Rules	None	Start collecting data for reporting to U.S. EPA for the first time in 2011.	Report to U.S. EPA for the first time.	In addition to complying with the U.S. EPA rule, they are subject to the CA rule for the first time.
Cost Attribution	None	Resources spent on sampling and collecting data are attributed entirely to U.S. EPA.	Resources spent on sampling, collecting data, and reporting are attributed entirely to U.S. EPA.	Regulated entities comply with the U.S. EPA rule, but may incur marginal costs to comply with the additional requirements in the revised CA rule. Report to U.S. EPA directly (along with the additional data required by CA only).

Table VI-2c. Regulated entity subject to both the current and revised California rules, but not the U.S. EPA rule (Examples: electricity deliverers, geothermal power plants, and electricity generating and cogeneration facilities with <25,000 $MTCO_2e$ emissions)

	2009	2010	2011	2012 and beyond
Subjected Rules	Report under the current CA rule.	Report under the current CA rule.	Report under the current CA rule.	The proposed revised rule becomes effective
Cost Attribution	Costs are entirely attributed to the current CA rule.	Costs are entirely attributed to the current CA rule.	Costs are entirely attributed to the current CA rule.	Regulated entities may incur some incremental costs to comply with the additional requirements in the revised CA rule or see a net savings from the reduced requirements from the current rule.

Table VI-2d. Regulated entity not subject to any reporting rule currently, but will be subject to the revised California rule (Examples: certain fuel suppliers; any industrial facilities with combustion emissions greater than 10,000 $MTCO_2e$ but less than 25,000 $MTCO_2e$ that are not currently reporting)

	2009	2010	2011	2012 and beyond
Subjected Rules	None	None	None	The proposed revised rule becomes effective
Cost Attribution	None	None	None	All new GHG reporting costs are attributed to the revised CA rule.

Table VI-2e. Regulated entity subject to the current California rule, but will no longer be subject to reporting under the revised rule (Examples: electricity generating and cogeneration facilities with >1MW capacity and between 2,500 and 10,000 $MTCO_2e$ of emissions)

	2009	2010	2011	2012 and beyond
Subjected Rules	Report under the current CA rule.	Report under the current CA rule.	Report under the current CA rule.	The proposed revised rule becomes effective. No longer need to report.
Cost Attribution	Costs are entirely attributed to the current CA rule.	Costs are entirely attributed to the current CA rule.	Costs are entirely attributed to the current CA rule.	Cost saving.

2. Costs Categorization of Affected Facilities

To estimate incremental costs incurred by reporting entities to comply with the proposed rule revisions, staff categorized the affected entities by applicable changes in reporting requirements resulting from the revisions. To the extent possible, staff categorized the reporting entities into facility types that will be affected by the revised rule in different ways, as some existing tasks are no longer required after the rule harmonization and new compliance tasks become effective under the revised rule. The U.S. EPA rule requirements implemented are by emission units (i.e., distinct emissions sources or equipment at facilities). However, the existing California rule takes a primary industry "sector" approach. Therefore a facility may be subject to reporting under multiple subparts of the U.S. EPA rule, which in come cases prevents the precise alignment of ARB and U.S. EPA facility categories before and after the rule revision.

Due to the intertwining requirements of the existing California rule and the U.S. EPA rule that form the baseline of this analysis, different types of facilities within the same industry sector will see different incremental impacts from the proposed rule revision. In most cases, one industry sector can often be categorized into several facility types, with each expecting to see different incremental impacts. For example, the electricity generating sector is further categorized into 7 facility types: Part 75 facilities, non-Part-75 facilities that emit >25,000 MT of CO_2e, facilities that emit 10,000 to 25,000 MT of CO_2e that use natural gas as primary fuel, facilities that emit 10,000 to 25,000 MT of CO_2e combusting fuels that may require fuel sampling, facilities that emit less than 10,000 MT of CO_2e that are currently reporting to ARB, geothermal facilities, and facilities with hydrogen fuel cell generating units. In contrast, the cement production sector does not need to be categorized into more detailed facility types because staff anticipates the incremental impacts are relatively uniform within this sector.

Staff categorized the affected facilities into 48 facility types in 16 industry sectors. The facility categorizations are listed in Table VI-3 along with the GHG reporting rules that they are subject to. For each facility category, staff summarized the changes in compliance tasks before and after the effective date of the proposed revised rule and estimated the costs of compliance for these tasks. The cost to perform a new task represents an incremental cost increase, while the cost to perform a current task that is no longer required under the revised rule represent an incremental cost saving (or a negative cost number). The following subsections describe the methodology that staff employed for the cost estimation.

Table VI-3. Reporting Entity Categorization

Industry Sector	Reporting Entity Category	Subject to: Current CA Rule	Subject to: U.S. EPA Rule	Subject to: Proposed CA Rule
Cement Production		✓	✓	✓
Electricity Deliverers	In-state retail provider with no electricity import from out-of-state	✓		✓
	In-state retail provider with electricity import	✓		✓
	Multi-jurisdictional retail providers	✓		✓
	Electricity marketer	✓		✓
Electricity Generation	Part-75 facilities	✓	✓	✓
	non-Part-75, >25,000 MT of CO_2e	✓	✓	✓
	10,000 to 25,000 MT of CO_2e, primarily natural gas fired	✓		✓
	10,000 to 25,000 MT of CO_2e, combusting non-natural gas fuels	✓		✓
	>1MW but <10,000 MT of CO_2e	✓		
	Geothermal facilities	✓		✓
	Facilities with hydrogen fuel cell EGU			✓
Cogeneration (stand-alone facility)[3]	≥25,000 MT of CO_2e	✓	✓	✓
	10,000 to 25,000 MT of CO_2e	✓		✓
	<10,000 MT of CO_2e and >1MW	✓		
Petroleum Refineries	Large refineries currently reporting to ARB as refineries	✓	✓	✓
	Small refineries currently reporting to ARB as general stationary combustion facilities	Note 1	✓	✓
Hydrogen Production	Stand-alone merchant plants	✓	✓	✓
	Stand-alone hydrogen plant with cogen	✓	✓	✓
Stationary Combustion	≥ 25,000 MT of CO_2e, can obtain fuel characteristic data from fuel suppliers	✓	✓	✓
	≥ 25,000 MT of CO_2e, need to conduct fuel testing	✓	✓	✓
	<25,000 MT of CO_2e			✓
Glass Production	>25,000 MT of CO_2e		✓	✓
	10,000 to 25,000 MT of CO_2e			✓
Lime Manufacturing			✓	✓
Nitric Acid Production			✓	✓
Pulp & Paper Mfg	>25,000 MT of CO_2e	Note 1	✓	✓
	10,000 to 25,000 MT of CO_2e			✓
Iron & Steel Production			✓	✓
Oil & Natural Gas System	Oil and gas exploration	Note 1	✓	✓
	Pipeline transportation of natural gas		✓	✓
	Natural gas distribution		✓	✓
Suppliers of Petroleum Products and Biofuels	Position holders- currently reporting as refineries	Note 2		✓
	Position holders- new to reporting			✓
	Enterers			✓
	Refineries producing LPG	Note 2	✓	✓
	Biofuel producers			✓

Suppliers of Natural Gas and NGL	Public utility gas corporation		✓	✓
	Publicly-owned natural gas utilities		✓	✓
	Interstate pipelines covered by Subpart NN		✓	✓
	Intrastate pipelines not covered by Subpart NN			✓
	NGL fractionators		✓	✓
	LPG consignees			✓
Suppliers of CO_2			✓	✓

Table Notes:
1. Some of the facilities in this category may be currently reporting to ARB as general stationary combustion facilities
2. Some of the facilities in this category may be currently reporting to ARB as refineries.
3. These are stand-alone cogeneration facilities that are not attached to other industrial operation.

3. Costs of Performing Compliance Tasks

A survey seeking reporting entities' inputs on costs of compliance was not conducted. Although such a survey can provide valuable data on the total costs incurred by reporting entities to comply with GHG reporting rules, it does not directly inform the incremental cost impacts of the revised regulation. A survey that provides relevant data for informing incremental costs would require a series of very extensive survey questions specific to each sector, and would be overly burdensome to potential respondents. Instead, staff utilized a method similar to an expert elicitation process to estimate the cost components, including labor costs (associated with monitoring, sampling, recording, training, and planning), fuel analysis cost, equipment cost, and verification cost, based on staff's experience in providing support to reporting entities and verification bodies. The method for estimating each cost component is described below.

Labor Costs

Since the inception of the California GHG reporting program in 2008, staff in ARB's Climate Change Reporting Section has been working closely with reporting entities in providing technical supports for emission calculations, providing training on the rule requirements and the use of the reporting tool, assisting reporters in preparing and submitting electronic GHG reports, and noting informal feedback from reporters on the time requirements of GHG reporting. Staff in ARB's Climate Change Verification and Protocols Section has been working closely with the accredited verifiers in ensuring the quality of GHG reports, observing the actual on-site practices of reporting entities (observations took place during verification site visits), and analyzing informal feedback provided by verifiers and reporters regarding the expenses of GHG reporting and verification. The staff in both sections has knowledge of the costs and efforts expended by reporting entities in complying with the GHG reporting regulation (ARB MRR 2007). Based on the knowledge acquired from this extensive experience in providing support and assistance to reporting entities, staff estimated ranges of costs and numbers of hours spent on certain compliance tasks.

Each staff in the two sections is a “sector lead” for one or several industry sectors covered by the GHG reporting rule and has developed knowledge of their sectors’ compliance practices. To methodically estimate the labor costs of certain compliance tasks, the staff members are asked a series of questions that are customized according to the specific facility categories identified previously. Some example questions may include:

> *“Describe what a typical facility in your sector is doing now for GHG reporting, describe what they will be doing after the revised rule is implemented, and describe the difference in compliance tasks;”*
>
> *“Based on your experience in observing reporters’ compliance practices during verification site visits, approximately how much time (in range of number of hours) is the staff at a typical refinery spending on coordinating and preparing records for verification?” or*
>
> *“Based on your experience in assisting reporters in emission calculation, approximately how much time is a typical technical staff at a cogeneration plant spending on collecting data and performing the distributed emission calculations required by the rule?”*

Following this approach, staff estimated ranges of time requirements for performing the following compliance tasks:

- Becoming familiar with rule requirements and the use of the reporting tool, preparing and implementing compliance monitoring plan for GHG reporting, and training facility staff in performing compliance tasks;
- Collecting data and calculating emissions using default emission factors;
- Collecting data and calculating emissions using fuel characteristic data (e.g. high heat value and carbon content) provided by the fuel suppliers;
- Collecting and analyzing fuel samples, keeping records of fuel analytical data, and calculating emissions at various periodic sampling frequencies;
- Monitoring proper operation of fuel measurement equipment and recording fuel use data;
- Measuring cogeneration system efficiencies for performing engineering calculations for distributing emissions between power production and thermal production;
- For electricity deliverers and suppliers of fuels, gathering data required for GHG reporting from their existing database system;
- For oil and gas facilities, complying with the additional monitoring and fuel testing requirements in storage tanks and acid gas removal units, as well as monitoring emissions during well unloading/cleanup;
- For each applicable sector, performing additional process emissions calculations called for by the respective sections of the proposed revised regulation;

- Entering data, performing quality assurance (QA) checks, and certifying GHG reporting submission in the reporting tool;
- Time avoided by not having to enter the same GHG reporting data into 2 different reporting tool systems for California and U.S. EPA;
- Identifying and selecting verification service providers, preparing conflict of interest application, and reviewing contracts with the verifier;
- Coordinating, preparing records for, and hosting verification site visits; and
- Following-up on verification and revising GHG report as needed.

Staff estimated the incremental time requirement of different compliance tasks that are expected for the 48 facility types in 16 sectors. Most facility types are expected to see only 1 to 4 incremental tasks listed above as the result of the rule change, although they may be already performing most of these tasks under the current California and U.S. EPA regulations.

For general compliance tasks that may be applicable to many sectors of various levels of complexity, such as fuel monitoring and verification, staff estimated different levels of time required to better represent the efforts needed for a facility. For example, a complex facility such as a refinery is likely to spend significantly more time preparing for and hosting a verification site visit than a simple facility such as an electricity generation plant with only one natural gas-fired engine. In this case, staff developed time requirement estimates for a simple, moderate, and complex facility for preparing and hosting the verification site visit, and applied them to each facility type appropriately. With these time requirement modules developed, the total labor costs for performing each compliance task are estimated by multiplying the estimated time requirement of the task by a range of wage rates (in $/hour) for the type of facility staff that typically performs the task.

Staff assigned each individual task to a class of facility staff that typically performs that task. Facility staff classes include administrative staff, technical staff, managerial staff, and lawyers. The technical staff class is further divided into two classes based on typical salary ranges: technical staff 1 may include junior engineers, scientists, senior operators, and senior technicians; and technical staff 2 may include mid to senior level engineers or compliance specialists.

The U.S. Bureau of Labor Statistics (BLS) 2009 Occupational Employment and Wage Estimates data (BLS 2009) for the state of California are used to construct ranges of wage rates. The wage data for several similar occupations that are likely to perform the compliance tasks are combined together to form the 5 facility staff classes in the analysis. For example, the technical staff 2 wage rate range is a composite of wage rates of chemical, civil, environmental, industrial, mechanical, and health and safety engineering occupations. The minimum 25th percentile, the maximum 75th percentile, and the average of the median wage rate values in the BLS data set are used as low, high, and mid estimates, respectively.

To account for the total labor costs incurred by the reporting entities, which may include employee benefits and overhead costs, staff applied the same adjustment factors that U.S. EPA used in estimating the economic impacts of the federal GHG reporting program (USEPA 2009a). These adjustment factors are a “benefit loading factor” of 0.5 and an “overhead loading factor” of 0.17. In other words, the ranges of wage rates extracted from BLS data are scaled up by a factor of 1.67 to obtain the final “loaded wage rate” numbers for the labor cost analysis. The resulting loaded wage rates for the 5 facility staff classes in 2009 dollars are summarized in Table VI-4.

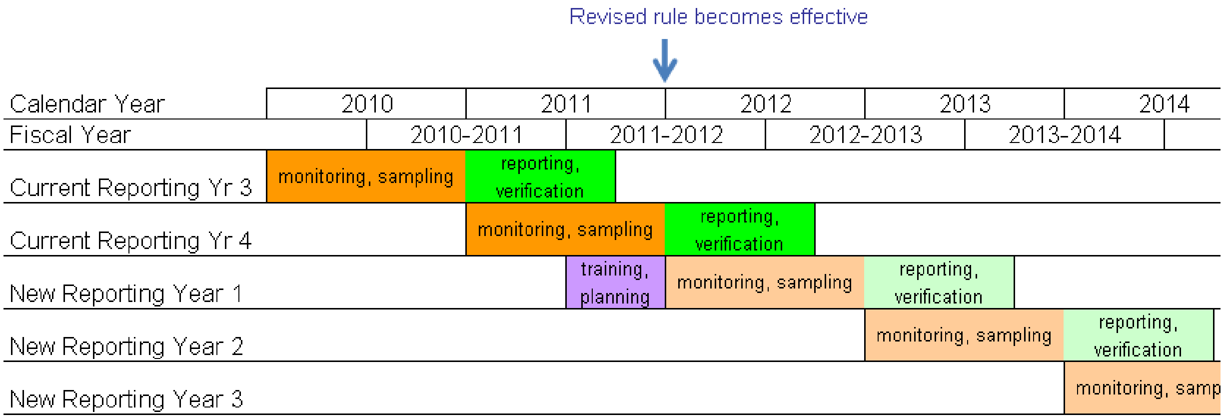
Table VI-4. Wage Rates Used to Estimate Labor Costs

Facility Staff Class	Loaded Wage Rate (2009$/ hour)		
	low	Mid	high
Administrative	21.41	23.54	27.25
Technical 1	34.52	47.85	62.91
Technical 2	51.15	68.81	79.63
Managerial	72.59	87.32	108.92
Lawyer	79.07	111.72	144.37

To estimate the labor costs of each facility type that will be affected by the revised rule in different ways, the labor costs of the applicable compliance task are summed to obtain the total incremental labor costs of the revised GHG reporting rule. For the current tasks that will no long be required under the revised rule, the costs for performing those tasks are subtracted (or represented by a negative value as cost saving).

To keep cost accounting on a yearly basis, staff summed the costs by yearly reporting cycle, which does not necessary coincide with a calendar year. For example, the labor costs for recording fuel use and collecting/analyzing fuel samples are expended during calendar year 1, but the labor costs for performing emission calculations and reporting those emissions released in calendar year 1 typically occur at the beginning of calendar year 2, and the costs for preparing and hosting verification typically occur in the middle of calendar year 2. (At the same time, while reporting and verification activities are underway during calendar year 2, the reporting entities are recording fuel use and collecting/analyzing fuel samples for the second reporting year.) The costs of these tasks together are considered the costs for “reporting year 1,” although the costs are spread into 2 calendar years. Figure VI-2 graphically illustrates the overlap of “reporting year,” “calendar year,” and “fiscal year.”

Figure VI-2. Reporting Year, Calendar Year, and Fiscal Year



Equipment Costs

Staff anticipates that most affected facilities, except for those in the oil and gas sector, will already have the necessary equipment in place for GHG reporting, either due to the existing California reporting rule or the U.S. EPA rule, by the time that the proposed rule revision becomes effective. Most of the incremental costs will be labor costs associated with the new compliance tasks, and most facilities should be able to meet the new requirements in the proposed rule without purchasing additional equipment. Some facilities may choose to install backup monitoring equipment to ensure data quality beyond the rule requirements, but staff does not expect that this will be common and did not include these costs in the analysis.

The proposed rule requires oil and gas system facilities to meter natural gas flow to pneumatic actuated pumps and high bleed devices, and to use a portable choke valve metering device to monitor well emissions during well unloading. Some facilities will need to purchase this equipment to comply with the revised rule. Staff estimated that a gas flow meter costs approximately $1,000-$2,000 to purchase and install, and a portable choke valve metering device costs approximately $500-$600. Because these new purchases are not significant capital investments, and oil and gas system facilities are likely able to purchase the equipment without financing or loan, staff chose not to annualize these capital costs over multiple years and assumed that these costs are incurred during the first year of the revised regulation implementation.

Fuel Analysis Costs

In California, most facilities use natural gas as their primary fuel. They will be able to use either the default emission factor or the high heat value provided by the fuel suppliers to calculate emissions. Suppliers of coal and petroleum coke typically provide carbon content data to their customers in billing records, giving facilities that combust these fuels the option to calculate emissions without fuel sampling and analysis. The proposed revised rule also allows facilities that combust standard liquid fuels (e.g. gasoline, diesel, fuel oils, LPG) and biofuels except digester gas (e.g. wood, agricultural byproducts, biodiesel) to calculate emissions using default emission factors. For other fuels, depending on the equipment size and amount of fuel used, some facilities would be required to collect and analyze periodic fuel samples to determine fuel characteristics for emissions calculation purposes.

In addition to estimating the time requirements for a typical facility to collect fuel samples and analyze them in-house, staff also contacted a few commercial laboratories in the state to obtain cost quotes of fuel analysis. In general, a simple fuel analysis of moisture content, carbon content or higher heating value may cost $70 to $120 if analyzed by commercial laboratories, or $35 to $190 if analyzed in-house (actual costs may depend on the capacity and efficiency of the in-house staff; it is assumed that facilities that are already sampling fuels on a frequent, regular basis for either the existing GHG reporting requirements or other operational purposes will likely take less time per fuel sample). Staff also obtained a cost quote of $600 to $800 from a commercial laboratory for gas content analysis required for oil and gas system facilities. Staff applied these costs to the incremental fuel sampling tasks expected under the revised regulation.

Verification Costs

In working closely with the accredited verifiers and collecting feedback informally provided by verifiers and reporters, staff has compiled estimated ranges of verification service fees that reporting entities spent to comply with the existing verification requirements. The year 2010 is the first year that verification is required under the current GHG reporting rule, and verifiers and reporters alike are learning the process for the first time and spending more time on working out details and developing expertise. After the issues encountered have been worked out and reporters have updated their monitoring plans or emissions calculations during the first mandatory verification cycle, staff expects that the verification service fee in the on-going years will be lower than in this first year.

Using the ranges of verification service fees in the first year and the estimated time requirements for verifiers to perform specific verification-related tasks, staff estimated the likely ranges of verification service fees in the future years, which could either be an intensive verification or less-intensive verification (see Section IV of this report for a discussion of verification requirements). Most facilities will need to go through an intensive verification at least once in every 3 years, and it is assumed that for the other 2 years, approximately half of the facilities will have no major issues to warrant an intensive verification and a less-intensive verification will suffice.[7] Staff estimated the ranges of verification service fees and the time requirements for facility staff to perform various verification-related tasks during both intensive and less-intensive verifications,

[7] A site visit and new contract establishment is not required for less-intensive verification, which reduces labor costs associated with verification by approximately 40%-50% when compared to a year that intensive verification is needed.

and applied these costs to each facility types for the first year and for on-going years. The annual verification cost in the on-going years is a composite of the cost expected for a typical intensive verification year and a typical less-intensive verification year, where each is weighted equally at 50%.

Oil and Gas Sector

The oil and gas system sector is handled differently from the other sectors affected by the proposed rule because the U.S. EPA has not adopted 40 CFR Subpart W—*Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems* (USEPA 2010w) at the time of this fiscal analysis, though a draft rule has been published and the final rule will likely be adopted before this proposed regulation revision is implemented. See Section III.N of this report for a more detailed discussion of California's proposed harmonization with Subpart W and the additional requirements for this sector.

The U.S. EPA estimated the first-year costs to comply with Subpart W are approximately $24,000 per crude petroleum and natural gas extraction entity, $18,000 per pipeline transportation of natural gas entity, and $11,000 per natural gas distribution entity (USEPA 2009b). The second year costs are approximately half of the first-year costs. To support cap-and-trade, the proposed California regulation will require additional sampling, monitoring, and calculation tasks beyond those required in Subpart W. Staff estimated the incremental costs to comply with the additional requirements in the proposed rule using the methods described in this section.

Under the baseline scenario in which U.S. EPA adopts Subpart W, only the California-only incremental costs are attributed to the proposed California rule. On the other hand, under another baseline scenario in which Subpart W is not adopted by U.S. EPA and California carries forward the requirements in the proposed Subpart W as well as the additional reporting requirements specific to California reporters, the incremental costs would be approximately the costs to comply with Subpart W estimated by U.S. EPA plus the incremental costs that staff prepared in this analysis.

Moreover, under the current California GHG reporting rule, oil and gas exploration facilities are reporting using the existing "facility" definition.[8] In the proposed revised

[8] The current GHG reporting rule (ARB MRR 2007) defines "facility" as: *"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. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.* On the other hand, the U.S. EPA GHG reporting rule (USEPA MRR 2009) defines oil and gas production reporting entities by the production "basin", regardless of how "contiguous or adjacent property" boundaries are drawn using the "facility" definition. In other words, if an operator operates 4 oil & gas exploration "facilities" in a basin, the operator will be reporting them as one entity in the GHG reporting program, regardless of how each of these "facilities" may be defined by "contiguous and adjacent property."

rule, California is harmonizing with U.S. EPA's "geological basin" approach. Therefore, reporting entities in California will also report by geological basins after the implementation of the proposed rule. Staff expects that some oil and gas exploration "facilities" that are currently reporting to ARB will be combined under the "basin" approach, and some existing oil and gas "facilities" that are below the current 25,000 MT of CO_2e reporting threshold and are not currently reporting to ARB will be incorporated into the reporting entity's inventory in the future. New oil and gas entities with 10,000 to 25,000 MT of CO_2e of emissions will also come into the GHG reporting program as abbreviated reporters.

Due to these changes, it is difficult to project the number of reporting entities and their incremental costs per facility. However, staff estimates that there may be a total of 12 to 38 oil and gas exploration entities reporting under the "basin" approach, and their costs of compliance will vary significantly among the entities. Although staff does not have an accurate projection of the number of affected oil and gas exploration entities at this time, the state-wide costs for the additional monitoring, sampling, and reporting requirements for crude oil storage tanks, acid gas removal unit, and well cleanup activities can be estimated from the state-wide equipment inventory maintained by ARB's Stationary Source Division (ARB O&G Survey 2007). Unlike what was done for the other sectors, for which we first calculated the costs per entity by incremental compliance tasks, then multiplied the cost per entity by the number of projected reporting entities to obtain the state-wide costs, for this sector, staff first estimated the state-wide incremental costs to comply with the additional requirements in the proposed rule, then divided the state-wide costs by the likely range of number of reporting entities to obtain the per-entity costs (ARB O&G Survey 2007).

State and Local Government

GHG reporting as specified is mandatory for any facility or entity that meets the regulation's applicability requirements. Therefore, some public agencies are 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 10,000 metric tons of CO_2 from stationary combustion sources. The Department of Water Resources is also expected to have a reporting requirement related to imported power. To estimate the economic impacts on state and local government entities, the following steps were taken.

First, staff reviewed the list of currently reporting entities and identified the local government agencies that are subject to reporting, including cities, counties, public utility districts, or other public entities that maintain facilities that are subject to reporting. Staff identified 10 state government agencies and 126 local government entities that are currently in the GHG reporting program (ARB GHG Summary 2010). Staff also reviewed a separate list (ARB CEIDARS 2007) of potentially affected entities that are not currently reporting GHG emissions to ARB but may be newly subject to the proposed regulation's revised threshold. The potentially affected entities list is based on an older inventory of emission sources compiled by ARB staff using information requested and obtained from the local air quality management districts and air quality control districts. Although it can provide a general sense of the number of potentially affected entities, it is not a precise projection of which entities may be affected. Each potentially affected entity must conduct a GHG emission inventory to determine their applicability to the revised regulation. Staff estimated that there may potentially be 11 additional state and local government entities subject to GHG reporting.

Second, staff sorted these state and local government entities into the appropriate facility categories in the electricity deliverer, electricity generation, cogeneration, and general stationary combustion sectors (see Section C.2, Costs Categorization of Affected Facilities for a description of the facility categorization). Among these public entities, 26 electricity generating or cogeneration facilities owned by local government entities are currently subject to reporting (due to the existing 1 MW and 2,500 $MTCO_2e$ threshold) but have emissions less than 10,000 MT of CO_2e and will therefore no longer need to report under the revised regulation.

Third, to estimate the costs to state and local government entities, staff multiplied the number of entities in each facility category by the expected incremental costs per facility for the respective facility category, which were calculated using the approach described in the previous subsections. Like their counterparts in the private sectors, publicly owned electricity generating and cogeneration facilities that emit less than 25,000 MT of CO_2e, as well as public electric utilities, are expected to see a cost saving from the significantly reduced reporting requirements, while the other facilities can expect to see a slight incremental cost increase for reporting.

Lastly, the estimated costs for each facility category are summed to obtain the net state-wide costs to local and state government. The results are presented in Section D.

Small Businesses

ARB does not collect small business status information from reporting entities under the current GHG reporting regulation. Staff does not know exactly which affected entities qualify as a small business, which is defined by the California Department of General Services as a business that meets all of the following qualifying criteria (DGS 2010):

1) It is independently owned and operated; and
2) The principal office is located in California; and
3) The officers of the business in the case of a corporation; officers and/or managers, or in the absence of officers and/or managers, all members in the case of a limited liability company; or the owner(s) in all other cases, are domiciled in California; and
4) It is not dominant in its field of operation(s); and
5) It is either:
  (A) A business that, together with all affiliates, has 100 or fewer employees, and annual gross receipts of fourteen million dollars ($14,000,000) or less as averaged for the previous three tax years, as

adjusted by the Department pursuant to Government Code Section 14837(d)(3); or

(B) A manufacturer as defined herein that, together with all affiliates, has 100 or fewer employees.

For affected industry sectors that cover only 1 NAICS code with a homogenous product, and for which we have a complete list of no more than 10 affected facilities in the entire sector (cement production, hydrogen production, lime manufacturing, nitric acid production, and iron & steel production), staff invested the time to query each facility's parent company one-by-one in the Dun & Bradstreet Selectory database (D&B 2010) to determine if they meet both the revenue criteria above (Criteria 5(A)) and the number of employees criteria (Criteria 5(B)). It was determined that there are no affected small businesses in these sectors.

Given that the Dun & Bradstreet Selectory database does not include all the affected entities covered by the GHG reporting program, Dun & Bradstreet data were not used to determine the number of small businesses for the remaining sectors. Instead, staff estimated the likely proportions of small businesses in each affected sector using employment statistics published by other government agencies. Only Criteria 5(B), 100 or fewer employees, was used for the estimation due to the limited scope of those employment data. This criterion provides a conservative high estimation because qualified small businesses that meet all 6 criteria will be a smaller subset of the businesses that have 100 or fewer employees. Staff used a combination of estimation techniques that are described in the following subsections.

Upper Bound Estimation. The California Employment Development Department Labor Market Information Division publishes data on the number of establishments by size category classified by the North American Industry Classification System (NAICS) (CEDD 2009).[9] This dataset contains estimated numbers of establishments that fall into nine "employment size categories" (e.g. number of establishments with "0-4 employees," "50-99 employees," "1000+ employees," etc.) for NAICS sectors at the 2-digit or 3-digit level. The NAICS codes reported by the entities that are currently in the GHG reporting program are mapped to the 2-digit or 3-digit NAICS codes in the CEDD dataset. The size categories in CEDD data are then aggregated into two employment size categories: "less than 100 employees" and "greater than 100 employees." The proportion of establishments that have less than 100 employees is calculated for each sector.

The general stationary combustion sector, the oil and gas system sector, and the suppliers of natural gas and natural gas liquid sector include facilities belonging to

[9] According to the U.S. Bureau of Labor Statistics, "an establishment is a single physical location at which business is conducted and/or services are provided. It is not necessarily identical with a company or enterprise, which may consist of one establishment or more." (US Census 2007). Examples include product and service sales offices (retail and wholesale), industrial production plants, processing or assembly operations, mines or well sites, and support operations (such as an administrative office, warehouse, customer service center, or regional headquarters). Each establishment should receive, complete, and return a separate census form. (US Census 2002)

multiple 3-digit NAICS codes. For these sectors, the proportions of “less than 100 employees” entities for the different NAICS codes are averaged to obtain a single proportion value for these sectors.

The estimated numbers of small business entities are calculated by multiplying the proportion of “less than 100 employees” establishments by the projected number of affected entities in each sector. These numbers are upper bound estimates that grossly overestimated the numbers of affected small businesses. The overestimation is due to the following reasons: 1) using only 1 of the 6 small business criteria to conduct this analysis captures a larger group of entities than the actual qualified small businesses; 2) given that a business can own multiple establishments, the actual number of affected businesses should be smaller than the number of affected establishments; and 3) given that entities with high emissions tend to have higher outputs, leading to higher revenues and driving higher fuel consumption, the entities that exceed the reporting thresholds (of 25,000 MT of CO_2e or 10,000 MT of CO_2e) are less likely to meet the revenue criteria of qualified small business. We anticipate that in reality, the proportions of “less than 100 employees” establishments should distribute unevenly at the different emissions levels (i.e. “2,500 to 10,000 MT of CO_2e” group, “10,000 to 25,000 MT of CO_2e” group, and “>25,000 MT of CO_2e” group), which determine the applicability of the regulation. The actual number of affected small businesses should be considerably smaller than the conservatively high estimates obtained using this approach. Further refinements that adjust for the uneven distribution of “less than 100 employees” entities are discussed next.

<u>Refined Estimation</u>. To account for the uneven distribution of small businesses at the different emissions levels, staff further refined the estimation using additional data sources and the assumption that high emitting facilities with >25,000 MT of CO_2e emissions tend to fall into the “greater than 100 employees” group.

The California Regional Economies Employment (CREE) Dataset published by the California Employment Development Department (CREE 2008) contains total numbers of establishments in each sector by NAICS codes up to the 6-digit level. The NAICS codes reported by the entities that are currently in the ARB GHG reporting program are mapped to the CREE data to obtain the maximum potential numbers of establishments in each affected sector. The total number of establishments is multiplied by the proportion of “greater than 100 employees” to obtain an estimated total number of entities that have greater than 100 employees. The estimated number of affected small business entities is the difference between the projected number of affected entities and the estimated number of “greater than 100 employees” entities. If the estimated number of “greater than 100 employees” establishments is substantially greater than the projected number of affected entities for an industry, it is an indication that all the top ranking employers in this industry are probably subject to GHG reporting, and we conservatively assumed that there is at least 1 small business entity in this sector.

The sector of suppliers of petroleum products is not specific to any one NAICS code, and the numerous NAICS codes that it potentially covered resulted in tens of thousands of establishments counted in the CREE dataset. Also, the CREE dataset does not have establishment counts for the potential NAICS codes covered under the supplier of natural gas and natural gas liquids sector. For these fuel supplier industries, the number of affected small business entities are calculated by multiplying the estimated proportion of “less than 100 employees” entities by the lower bound and higher bound of the projected number of total entities. Similarly, general stationary combustion facilities include numerous NAICS codes that resulted in tens of thousands of establishments counted in the CREE dataset. The likely number of small business entities is estimated by multiplying the projected number of affected entities by 37%, the proportion of small businesses based on sampling 25 existing general stationary combustion entities that staff individually queried using the Dun & Bradstreet Selectory database (D&B 2010).

The electricity deliverer, electricity generation, and cogeneration entities are aggregated under NAICS code 221. Since there is no one-to-one correspondence between the regulation sectors and NAICS codes, CREE does not inform the total number of establishments that are utilities versus electricity generation or cogeneration facilities. For electricity deliverers, staff estimated the number of potential small business entities by first eliminating the utilities owned by local governments or other large well-known energy corporations from the current reporter list, then multiplying the remainder by the estimated proportion of “less than 100 employees” establishments obtained from CEDD. For facilities subject to electricity generation and cogeneration regulation requirements, staff estimated the number of potential small business entities by multiplying the total number of establishments in NAICS code 22111 (electricity power generation) by the proportion of “less than 100 employees” entities.

Using the estimation techniques described above, staff conservatively estimated that there may be approximately 186 small business entities affected by the proposed regulation, with an upper bound no greater than 268. The estimated numbers of affected small business entities by sector are summarized in Table VI-5. Again, these numbers likely represent an overestimation due to the use of only 1 (out of the 6) small business criteria and also due to multiple establishments owned by one business. The actual number of affected businesses should be smaller than the number of affected establishments.

Table VI-5. Estimated Numbers of Affected Small Business Entities

Industry sector	Number of reporting entities	Proportion of establish-ments with <100 employees	Maximum number of establishments in covered NAICS	Estimated number of small business entities	Upper bound estimate
Cement Production	10	NR[1]	21	0	NR[1]
Electricity Deliverers	88	23%	62	5	21
Electricity Generation	192	23%	284	39	45
Cogeneration	55	23%		11	13
Petroleum Refineries	24	19%	25	4	5
Hydrogen Production	6	NR[1]	63	0	NR[1]
Stationary Combustion	184	42%	>10,000 [2]	68	78
Glass Production	15	64%	15	10	10
Lime Manufacturing	1	NR[1]	5	0	NR[1]
Nitric Acid Production	2	NR[1]	26	0	NR[1]
Pulp & Paper Manufacturing	9~11	47%	51	1	6
Iron & Steel Production	1	NR[1]	55	0	NR[1]
Oil & Natural Gas Sys	47	44%	169	1	21
Suppliers of Petroleum Products and Biofuels	45~60	67%	>10,000 [2]	30	41
Suppliers of Natural Gas and NGL	40~58	42%		17	25
Suppliers of CO_2	7	34%	63	1	3
TOTAL	**~750**			**~186**	**~268**

Table notes:
1. Staff conducted one-by-one query of the affected facilities in the Dun & Bradstreet Selectory database and found no small business entities affected by the regulation in this sector. Therefore, the proportion of "less than 100 employees" and upper bound estimate are not relevant.
2. These industries are not specific to any one NAICS code, and the numerous NAICS codes that it potentially covered resulted in a maximum potential of more than ten thousand establishments counted in the CREE dataset.

D. Economic Impacts of Proposed Regulation

This section presents the results of staff's analysis on the economic impacts of the proposed regulation. We first present a state-wide overview of the cost impacts by affected sectors, which includes all of the affected entities in the private and public sectors. The following subsections discuss the impacts on private businesses, small businesses, state and local agencies, consumers, employment, business creation and elimination, and California business competitiveness.

1. Overview of State-Wide Costs by Sector

Only the direct incremental costs of complying with the proposed reporting regulation, beyond the costs that most facilities would already incur in meeting either the extant California requirements or the U.S. EPA requirements, are included in this analysis.

Using the methods described above in Section C, staff's estimates of the cost impacts for each affected sectors are summarized in Table VI-6, which include all the affected entities in the private and public sectors.

Table VI-6. Statewide Incremental Cost Impacts by Sector

Sector	Number of Reporting Entities	Incremental Costs ($1,000)[1]			
		First-Year	[Range]	On-going Years	[Range]
Cement Production	10	10	[3 : 20]	10	[3 : 20]
Electricity Deliverers	88	-150	[-34 : -250]	-230	[-110 : -350]
Electricity Generation	192	-240	[-180 : -390]	-260	[-150 : -330]
Cogeneration [2]	55	-29	[-31 : -34]	-52	[-35 : -50]
Petroleum Refineries	24	180	[66 : 530]	110	[36 : 250]
Hydrogen Production	6	58	[30 : 162]	51	[26 : 155]
Stationary Combustion	184	920	[420 : 1,800]	580	[220 : 1,200]
Glass Production	15	67	[32 : 110]	48	[24 : 96]
Lime Manufacturing	1	5	[3 : 9]	4	[2 : 7]
Nitric Acid Production	2	31	[16 : 50]	22	[12 : 45]
Pulp & Paper Manufacturing	9~11	49	[23 : 90]	23	[10 : 49]
Iron & Steel Production	1	5	[3 : 9]	4	[2 : 7]
Oil & Natural Gas System [3]	47	650	[200 : 1,800]	510	[140 : 1,600]
Suppliers of Petroleum Products and Biofuels	45~60	1,170	[390 : 2,200]	720	[320 : 1,300]
Suppliers of Natural Gas and NGL	40~58	650	[180 : 1,500]	400	[150 : 860]
Suppliers of CO_2	7	42	[26 : 73]	36	[18 : 53]
STATE-WIDE TOTAL	**approx. 750**	**3,400**	**[1,200 : 7,700]**	**2,000**	**[700 : 4,900]**

Table notes:
1. All costs are in 2009 dollars. A negative cost number indicates a cost saving.
2. The cogeneration sector consists of facilities whose primary business is cogeneration. This does not include cogeneration units that are a part of a larger industrial operation.
3. For the oil and gas system sector, the costs shown here do not include the baseline costs to comply with U.S. EPA Subpart W.

As shown in Table VI-6, the proposed rule revision is expected to have a net state-wide incremental cost impact of $3 million ($1–$8 million) in the first year and $2 million ($1–$5 million) in the on-going years. Using a discount rate of 5% and a time horizon of 10 years, the total state-wide costs are approximately $18 million ($6 to $43 million) over 10 years. A 10-year time horizon is assumed for the analysis because ARB staff expects that the GHG reporting regulation may potentially be revised again between 2012 and 2022, due to potential new federal regulations or cap-and-trade program requirements.

The electricity deliverer, electricity generation, and cogeneration sectors can expect to see a net incremental cost saving from the revised regulation due to reductions in California reporting requirements. The other sectors are expected to see a net incremental cost increase due to additional monitoring, sampling, and reporting requirements in the proposed regulation. State-wide, most of the incremental costs are borne by those entities that are new to GHG reporting, including suppliers of fuels (approximately 46% of state-wide costs) and general stationary combustion sources that emit 10,000 to 25,000 MT of CO_2e that will be new to GHG reporting under the proposed regulation (approximately 23% of the state-wide costs). In addition, the oil and gas sector is expected to incur approximately 19% of the state-wide costs due to the additional monitoring and sampling requirements proposed in this revised regulation. The incremental costs to the other sectors make up the remaining 12% of the state-wide costs. The distribution of net costs and net savings by sectors over the 10-year time horizon are graphically presented in Figure VI-3 and Figure VI-4, respectively.

The main sources of uncertainties in the economic impact analysis are from the ranges of wage rates in the U.S. Bureau of Labor Statistics data and the ranges of the estimated time requirement to perform compliance tasks. The high estimates shown in the cost table represent the worst case scenario, in which all the affected entities in each sector use staff whose salary is high in their respective staff class, and the amount of time that the high-salaried staff takes in doing the compliance tasks is also on the high end of the range of estimates. On the other hand, the low estimates represent the best case scenario, in which all the affected entities in each sector use staff whose salary is on the low side of the wage rate range, and each staff takes little time to accomplish the compliance tasks. The high and low estimates are shown here for bounding purposes, and they are extremely unlikely in reality because there is a diversity of facility staff salaries and efficiencies across the sector. When factoring in all uncertainties in either direction, the net costs are likely to be close to the middle estimates.

Figure VI-3. Distribution of Net Incremental Costs by Industry Sector

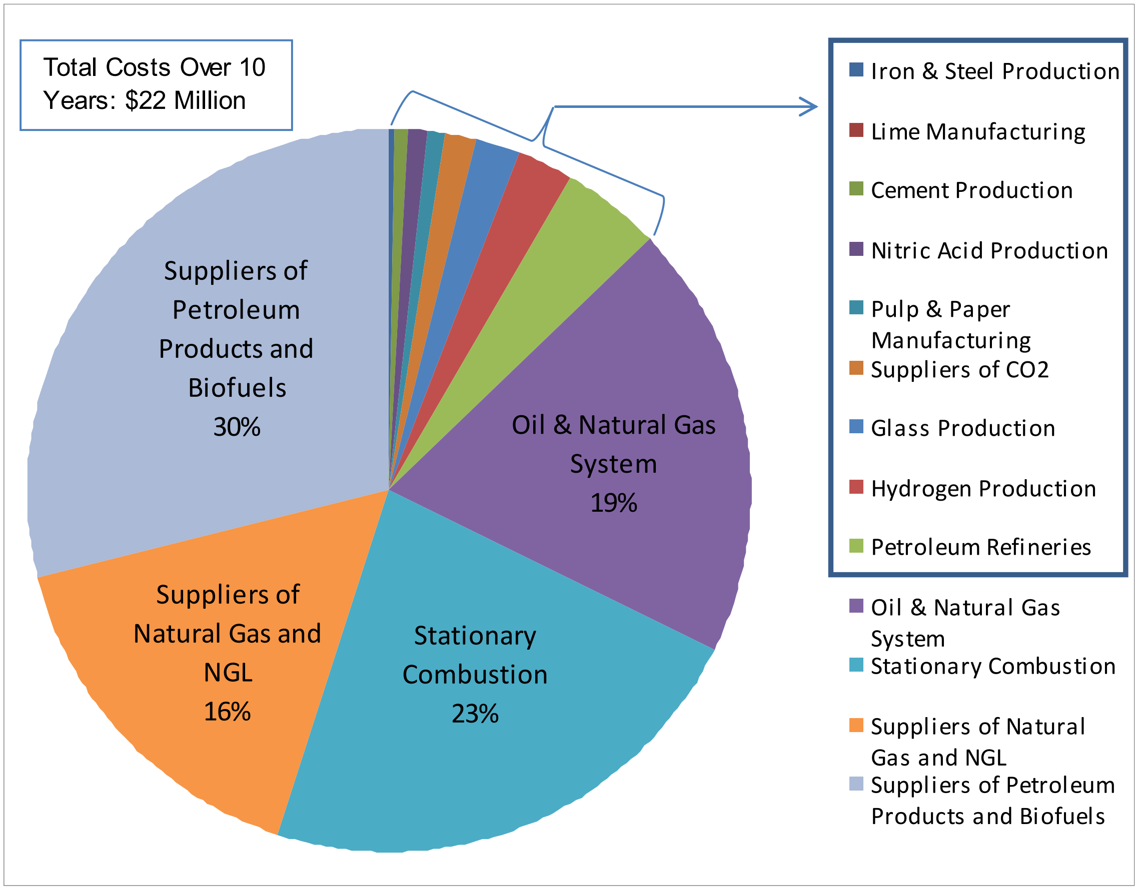


Figure VI-4. Distribution of Net Incremental Saving by Industry Sector

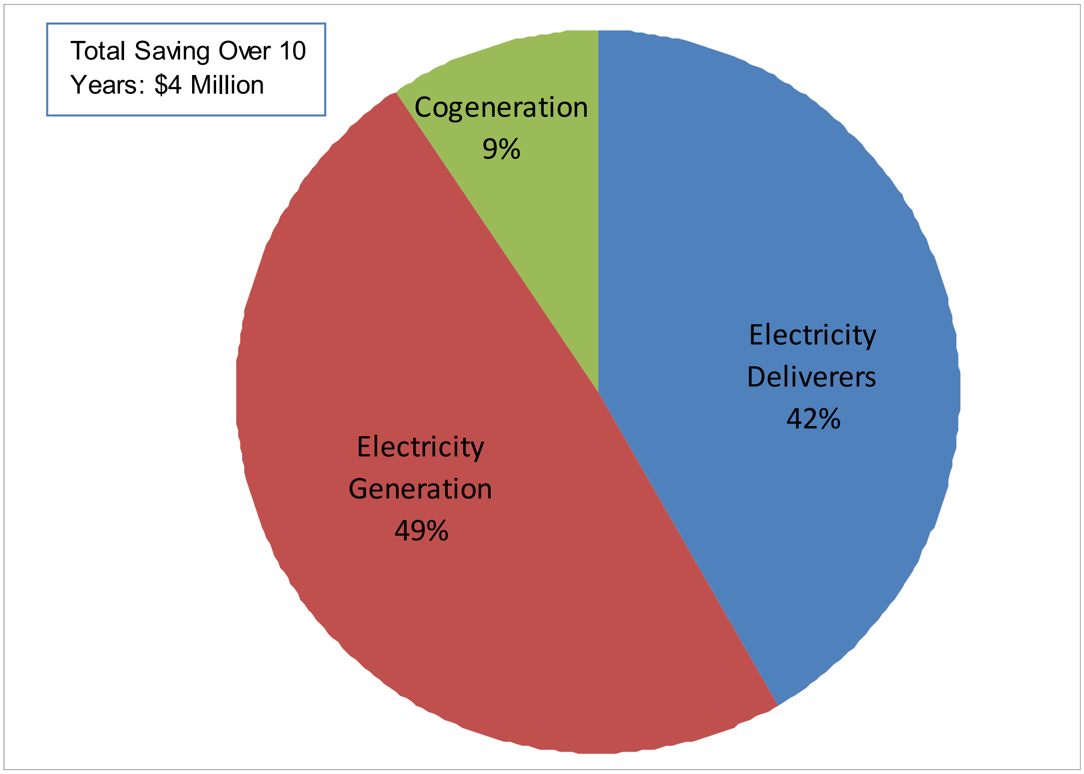
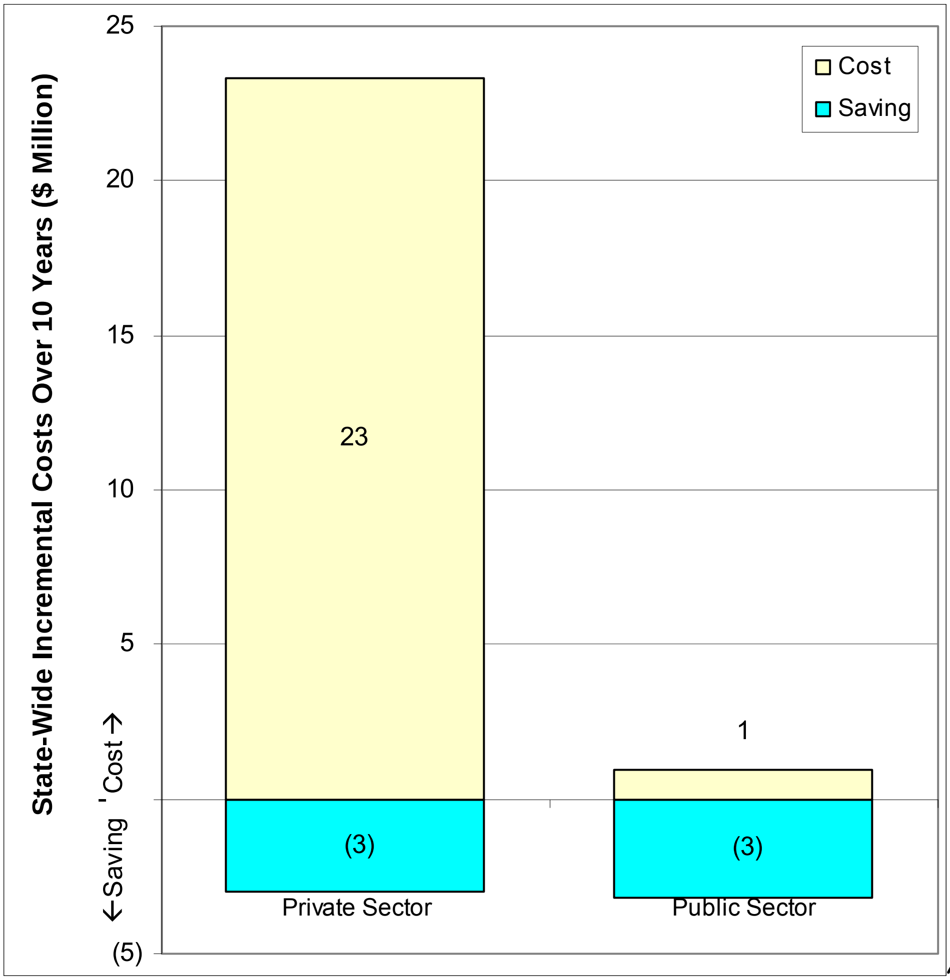


Table VI-6, Figure VI-3, and Figure VI-4 show the estimated costs to all affected entities in the private and public sectors. The total state-wide costs broken down by private and public entities are shown in Figure VI-5. The private sector incurs a majority of the incremental costs, while the net saving is distributed equally in the private and the public sectors. The cost impacts on private businesses and state and local government are discussed in further details in the following sections.

Figure VI-5. State-wide Costs Incurred by Private and Public Entities



2. Impacts to California Businesses

The proposed GHG reporting regulation focuses on the largest stationary sources of GHG emissions and other sources that must be included for an effective cap-and-trade program. The majority of the GHG reporting costs will be incurred by private businesses.

The incremental costs for typical businesses subject to the proposed rule revision will generally be small for facilities that are already subject to current GHG reporting programs, because the bulk of the baseline costs will be incurred complying with the U.S. EPA regulation (USEPA MRR 2009-2010) and the existing ARB reporting regulation (ARB MRR 2007). For an individual reporting entity, the incremental cost per entity could range from a worst case estimate of an additional cost of $80,000 for a petroleum refinery to a best case estimate of a cost saving of $10,000 for an electricity deliverer entity.

The specific incremental cost for a facility subject to GHG reporting can vary significantly depending on each facility's unique situation in terms of its sector designation, type and size of its fuel combustion equipment, facility complexity, emissions level, and its current monitoring and sampling practices as compared to its future requirements under this proposal. Staff anticipates that those general stationary combustion facilities that are new to the GHG reporting program but emit less than 25,000 MT of CO_2e and can use the abbreviated reporting option will incur a new cost of approximately $1,000 to $3,000 per facility. Facilities that are not currently reporting to California but will be subject to U.S. EPA reporting rule are expected to incur all new verification costs. Complex facilities with a large number of processes or that require ongoing monitoring of fuels, such as refineries, will have higher verification costs (including verification service costs and company staff labor costs) which could range from $8,000 to over $60,000 per year. Relatively simple facilities, such as a glass production plant, can expect to see relatively lower reporting and verification costs, between $1,000 and $5,000 per year. Staff anticipates that the incremental costs of oil and gas entities will vary significantly among entities, ranging from $5,000 to $45,000 per year. Costs per reporting entity by industry sectors are presented in Table VI-7.

Some reporting entities are expected to see a net cost saving as the result of the proposed regulation. Within the electricity deliverer, electricity generation, and cogeneration sectors, three sectors that are expected to see a net incremental saving sector-wide, most facilities may see reduced costs due to reductions in reporting requirements, although some may experience a slight cost increase. Electricity generating or cogeneration facilities that emit less than 10,000 MT of CO_2e, but are currently reporting to ARB under a more stringent threshold of 1 MW and 2,500 MT of CO_2e, will likely see reduced costs because the proposed rule has significantly reduced their reporting efforts through the abbreviated reporting provision. Electricity generating or cogeneration facilities emitting less than 10,000 MT of CO_2e will experience a cost saving because they will no longer be required to report their emissions under the revised rule. Electricity retail providers (2/3 of which are public utilities) can also expect a cost saving due to significantly reduced reporting requirements. State-wide, approximately 58% of the net saving is in the electricity generation and cogeneration sector, and the remaining net saving is in the electricity deliverer sector.

Table VI-7. Range of Incremental Cost Impacts per Reporting Entity by Sectors in the On-going Years

Sector	Incremental Costs Per Entity in the On-going Years ($1,000)[1]	
	Low	High
Cement Production	<0.5	2
Electricity Deliverers	-10	<0.5
Electricity Generation	-9	3
Cogeneration[2]	-9	1
Petroleum Refineries	-1	81
Hydrogen Production	4	26
Stationary Combustion	<0.5	13
Glass Production	<0.5	7
Lime Manufacturing	2	7
Nitric Acid Production	6	22
Pulp & Paper Manufacturing	<0.5	7
Iron & Steel Production	2	7
Oil & Natural Gas System[3]	10	45
Suppliers of Petroleum Products and Biofuels	6	20
Suppliers of Natural Gas and NGL	<0.5	21
Suppliers of CO_2	3	8

Table notes:
1. All costs are in 2009 dollars. A negative cost number indicates a cost saving. Due to the complex baselines and the diversity of the facility types within an industry sector, some facilities in the same sector may experience a cost saving, while some may experience an incremental cost increase. (See Sections C.1 and C.2.)
2. The cogeneration sector consists of facilities whose primary business is cogeneration. This does not include cogeneration units that are a part of a larger industrial operation.
3. For the oil and gas system sector, the costs shown here do not include the baseline costs to comply with U.S. EPA Subpart W.

The sources of uncertainties for the cost per entity estimates come from ranges of wage rates and time requirements to perform compliance tasks. Similar to the state-wide costs by sectors, the high estimates represent the worst case scenario in which high-salaried facility staff take many hours to perform compliance tasks. In addition, because facilities within the same sector can be further categorized into more detailed facility types depending on how they are affected by the revised regulation (see Section C.2—Costs Categorization of Affected Facilities for a discussion of the facility categorization), a wide range of values for cost per entity can be expected even within the same sector.

With the proposed revisions, we anticipate that initial year costs will be highest, as reporters modify internal GHG reporting systems, become familiar with the new requirements, install any new equipment, and develop expertise with the new reporting systems and methods. We anticipate industry costs to decline over time as the revised GHG reporting requirements become incorporated into standard facility practices.

The Oil and Gas Sector and the Subpart W Baseline

For the oil and gas sector, under the likely scenario that U.S. EPA adopts Subpart W by the time that this proposal is promulgated, the incremental costs for implementing the proposed rule state-wide are approximately $0.7 million ($0.2—$2 million) in the first year and $0.5 million ($0.3—$1.5 million) in the on-going years. Each entity may possibly see an incremental cost increase of $5,000 to $52,000 in the first year and $2,000 to $45,000 in the subsequent years.

Under the unlikely scenario that U.S. EPA does not adopt Subpart W by the time that this proposed rule is promulgated, in which case the incremental costs are the sum of the costs to comply with Subpart W as well as the additional tasks required by the proposed California regulation, the total incremental costs to the oil and gas sector state-wide are projected to be in the range of $0.6 to $3 million in the first year, and $0.4 to $2 million in the on-going years. In this scenario, each entity may possibly see an incremental cost increase of between $16,000 and $76,000 in the first year and between $9,000 and $60,000 in the on-going years.

3. Impacts to Small Businesses

Using a combination of estimation techniques described in Section C of this chapter, staff conservatively estimated a total of approximately 186 small business entities that may be affected by the proposed regulation revision (with an upper bound estimate of no more than 270 small business entities). Other than their high-level industry sector designation, we do not know exactly how these small business entities distribute among the 48 facility categories, which determine whether an individual entity may incur a net incremental cost or see a net incremental savings. Nevertheless, we expect that more small businesses may be in the 10,000 to 25,000 MT of CO_2e category that are eligible for abbreviated reporting, and they should incur relatively less total costs than their counterparts with emissions >25,000 MT of CO_2e.

The estimation results presented in Table VI-5 show that approximately 40% of the small businesses may be in the general stationary combustion sector, 30% may be in the electricity generation and cogeneration sector, and 10% may be in the fuel supplier sector. The incremental costs among the facilities in these three sectors can vary significantly. Based on the estimation described in Section C, a small general stationary combustion facility in the <25,000 MT of CO_2e category may see an incremental cost ranging from a few hundreds dollars to an upper bound of $7,000. Because some small electricity generating and cogeneration facilities are relieved from certain reporting requirements, and some may no longer need to report, a facility in this sector may see an incremental savings of $3,000 to $7,000. On the other hand, small fuel suppliers may be newly subject to GHG reporting under the revised regulation, with a likely incremental cost ranging from $2,000 to $13,000.

4. Impacts to California State and Local Agencies

Using the methods described previously, we have estimated that State and local agencies will likely see an overall cost savings as the result of this proposal. The local governments and agencies that could be subject to reporting include some cities, counties, public utility districts, or agencies that maintain facilities such as landfills, sewage treatment plants, electricity generating or cogeneration units, or publicly owned electricity providers that meet the applicability criteria. In general, publicly owned electricity deliverers and electricity generating or cogeneration facilities with <25,000 MT of CO_2e emissions will see a net savings, while the other types of facilities will see an incremental cost increase. Statewide, the overall savings to local government entities are approximately $2 million ($1-3 million), and the savings to state government entities are approximately $50,000 ($30,000-$60,000) over the 10-year time horizon using a 5% discount rate. The incremental costs and savings are summarized in Tables VI-5 and VI-6.

Table VI-8. Costs to Local Government Entities Subject to Reporting

Facility Type	Number of affected entities	Total Costs over 10 Years ($million)[1]	
		Best Estimate	Range
Electricity Deliverer (municipal utilities/joint power)	41	-1.3	[-0.6: -2.0]
Facilities with EGU/cogen, >25,000 MT of CO_2e	46	0.6	[0.2 : 1]
Facilities with EGU/cogen, <25,000 MT of CO_2e	35	-1.6	[-0.8 : -2.5]
Other facilities	approx. 12	0.3	[0.1 : 0.5]
SUM	**134**	**-2**	**[-1 : -3]**

Table notes:
1. All costs are discounted by 5% over 10 years and stated in 2009 dollars. A negative cost number indicates a cost savings.

Table VI-9. Costs to State Government Entities Subject to Reporting

Facility Type	Number of affected entities	Total Costs over 10 Years ($1000)[1]	
		Best Estimate	Range
Electricity Deliverer	1	-15	[-7: -30]
Facilities with cogen, >25,000 MT of CO_2e	7	13	[-6 : 50]
Facilities with cogen, <25,000 MT of CO_2e	2	-77	[-40 : -100]
Other facilities	approx. 3	27	[10 : 50]
SUM	**13**	**-50**	**[-30: -60]**

Table notes:
1. All costs are discounted by 5% over 10 years and stated in 2009 dollars. A negative cost number indicates a cost savings.

Adoption of the proposed revisions is expected to require new funding for ARB to administer the program. Approximately 2.0 staff members will be redirected from existing staffing to administer the new program beginning in FY2011/2012. In addition, approximately $250,000 per year will be required over a three-year period for reporting system improvements as staff works to integrate California reporting with U.S. EPA reporting systems, and then an additional $150,000 per year is needed on an ongoing basis for operations and maintenance of the reporting systems. These costs are not included in existing budgeting and additional funds are needed to implement the proposed revisions to the regulation.

5. 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.

6. Impact on Employment

Since the incremental compliance costs associated with the revised GHG reporting regulation impose only a very small impact on California businesses, staff expects no significant change in employment due to the regulation revision. 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 estimated that the proposed revisions to the regulation will likely result in a small number of additional jobs in the technical consulting business. The adoption of the existing GHG reporting regulation has already led to accreditation of 230 new verifiers to date (see Section IV of this report). Most of these verifiers are existing technical consultants that have expanded their areas of business into providing annual verification services, but some may be new positions created to support the verification workload. To estimate the number of new verifier positions that may be needed under the revised regulation, staff scaled up the number of verifiers accredited by ARB to date (230) by the ratio of the expected number of GHG reports under the revised regulation and the number of the current GHG reports (750/609). To account for the part-time nature of verification work, we conservatively assume that for every four such new verifier positions demanded, only one new job will be created. It is estimated that 10 to 20 new verification jobs could be created to provide these additional services required by the proposed regulation.

For technical consulting jobs to assist reporting entities with GHG reporting activities, staff conservatively assumes that there will be no noticeable increase in consulting jobs, but we anticipate that work may be shifted to support the new reporting needs due to new or more complicated reporting requirements. Many facilities will hire consultants to setup GHG reporting systems in the first 2 years of rule implementation. However in the on-going years, some may choose to carry on GHG reporting with in-house staff without retaining a consultant’s assistance. There may be an initial growth in consulting business, but the growth will likely level off after 2 to 3 years. Staff expects that most consulting work will be done by existing firms and employees, and some of the work will be performed by firms outside of California. Current capacity in the technical consulting firms likely can support the additional requirements imposed by the proposed regulation. Precise estimates of the number of new jobs created are not possible.

7. 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.

Staff anticipates that although there may be new consulting and verification jobs created, there will be no noticeable changes in the number of businesses created, eliminated, or expanded as the result of the propose regulation. 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.

8. 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 interstate 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

California Government Code section 11346.2 requires ARB to consider and evaluate reasonable alternatives to the proposed regulatory action and provide reasons for rejecting those alternatives. This section discusses alternatives evaluated and provides reasons why they were not included in the proposed revised regulation. ARB staff did not find any of the alternatives considered to be more effective in carrying out the purpose for which the proposed revised regulation is intended, or to be as effective or less burdensome to affected businesses, than the proposed revised regulation.

A. Take No Action Alternative

A "no action" alternative means that no revisions would be made to the existing California GHG reporting regulation. Essentially, ARB and reporting entities would continue to operate pursuant to the requirements of the existing regulation. If ARB were to take no action, reporting entities subject to the existing GHG reporting regulation would prepare a California-specific emissions data report which was not harmonized with federal U.S. EPA reporting requirements, resulting in potential confusion, duplicative reporting efforts, and additional, unnecessary costs to California businesses subject to GHG emissions reporting. In addition, the ARB would incur additional burdens in resolving inconsistencies between reporting programs, maintaining redundant data systems, and providing additional user support.

By developing the current proposal, the California GHG emissions reporting requirements are substantially harmonized with U.S. EPA's mandatory GHG reporting requirements for most industrial sectors. The intention of the proposed revisions and harmonization is to allow emissions data reports prepared for California GHG emissions reporting to also meet the requirements of U.S. EPA's GHG emissions reporting. This reduces costs and duplicative reporting for California businesses. ARB is working with U.S. EPA to develop a mechanism so that ARB GHG emissions data reports can be submitted directly to U.S. EPA, rather than submitting separate California and U.S. EPA reports based on disparate requirements, methods, and emission reporting systems.

In addition, the current ARB regulation for mandatory GHG reporting is not sufficiently rigorous to support a cap-and-trade program for GHG emissions. For example, under the current regulation certain large combustion sources may simply use default emission factors for estimating their emissions, which is not sufficient for a cap-and-trade program. Or, under the current regulation, if certain critical data are missing, fully defined methods are not provided for providing the missing data. Also, under the current regulation many industry sectors are not required to report their process emissions. These changes and many other improvements have been added to the proposed regulation as part of the U.S. EPA harmonization and as needed for cap-and-trade. The development and implementation of a credible cap-and-trade program would not be possible under the existing regulation without the addition of a separate and additional regulatory process to require reporting of additional data needed to support cap-and-trade.

As such, the “no action” alternative would increase costs for reporting entities because they would be faced with submitting two completely separate emissions data reports, and would not sufficiently support California’s cap-and-trade program, whereas the proposed regulatory action would reduce reporting costs and avoid duplication by harmonizing substantial portions of the California GHG reporting regulation with U.S. EPA reporting requirements, while also including revisions to support a rigorous and stringent cap-and-trade program. For all of these reasons, the “no action” alternative was rejected.

B. Retain Existing Rule and Create New Mechanism for Collecting Cap-and-Trade Data

Another option that was considered was to retain the existing ARB rule, and create a separate regulatory reporting process to collect the additional data needed to support a viable cap-and-trade program. This option fails on several levels. First, it would add a third reporting program to the existing ARB reporting and U.S. EPA greenhouse gas reporting. Second, the benefits of harmonizing with the U.S. EPA reporting program, providing more consistent reporting and lower costs would not be realized. Third, the ARB would need to implement another new regulatory program, which would unnecessarily increase burdens on those subject to the cap-and-trade program, and create new, and sometimes redundant administrative and technical workload for the ARB. For these reasons, this option was rejected.

C. Create Regulation that is 100% Consistent with U.S. EPA Regulation or Revoke Existing ARB Regulation

ARB staff considered revising the California GHG reporting regulation to be completely consistent with the U.S. EPA reporting requirements for GHG emissions, essentially adopting the U.S. EPA regulations “as is.” Or, in the same vein, we considered revoking the existing ARB GHG reporting regulation so that ARB would obtain GHG data solely from the U.S. EPA reporting program.

The regulation is being revised to not only harmonize with U.S. EPA GHG reporting requirements, but to also support a California cap-and-trade program. The current U.S. EPA reporting regulation is not sufficiently rigorous to support a cap-and-trade program. For example, U.S. EPA’s regulation allows the use of default emission factors which would not provide emissions that are sufficiently accurate to support market-based emissions trading. The proposed revised ARB regulation limits the use of default emission factors in order to ensure the accuracy needed for a cap-and-trade program. The ARB proposed revised regulation also provides more prescriptive methods for handling missing data than the U.S. EPA requirements, which are not always sufficient to support the accuracy needed for a cap-and-trade program. In addition, electric power entities and operators of petroleum and natural gas systems are not required to report under the U.S. EPA regulation, but these sectors are critical for California’s GHG emissions accounting.

For these reasons, adopting the U.S. EPA reporting regulation “as-is,” or simply revoking the existing ARB regulation, would not effectively support critical ARB program needs, and ARB has therefore rejected this alternative

D. Modify the Existing California Regulation to Support Cap-and-Trade Program Needs without Harmonizing with U.S. EPA Reporting Requirements

Another option considered by ARB staff was to modify the existing ARB regulation so that it would meet cap-and-trade and other program needs, without consideration of the U.S. EPA reporting requirements. If the current ARB regulation was modified without consideration of the U.S. EPA reporting requirements, and similar to the “take no action” alternative, reporting entities would essentially be subject to two completely independent GHG reporting programs – one at the State level and one at the Federal level. Requiring facilities to develop and submit separate emissions data reports based on completely different requirements and specifications would be confusing and create additional costs. In addition, the ARB would incur additional burdens in resolving inconsistencies between reporting programs, maintaining redundant data systems, and providing additional user support.

In assessing this alternative, it quickly became apparent that including revisions to harmonize with U.S. EPA reporting requirements, along with the proposed revisions to support a cap-and-trade program, would provide efficiency and cost savings to both reporting entities and ARB. By using the U.S. EPA regulation as a baseline for the proposed revisions, and including additional California-specific modifications to ensure the stringency and accuracy necessary for California’s cap-and-trade program, ARB is allowing reporting entities to use essentially the same methods and assumptions as other reporting entities throughout the nation, providing state-to-state consistency. This is important for existing or future regional and national GHG trading programs.

ARB staff chose not to pursue the alternative of modifying the existing California reporting regulation to support cap-and-trade without harmonizing with U.S. EPA reporting requirements because it does not produce the same cost savings and reduced duplication as the proposed regulatory action, and would in fact increase costs and duplication. For all these reasons, ARB staff rejected this alternative.

E. Alternatives to Proposed Verification Requirements

Under the current GHG reporting regulation, ARB has about 230 accredited verifiers and 45 accredited verification bodies, all of whom have all met strict eligibility criteria under the existing regulation, taken ARB verifier training, and successfully passed an examination at the end of the training. These firms and individuals would be able to continue to provide verification services under the proposed revised regulation once the existing accredited verifiers have attended an ARB training workshop to learn the new reporting requirements under the proposed regulation.

ARB staff considered the following alternatives to assess the stringency and functionality of independent third-party verification in the proposed regulatory action.

Make No Changes to Current Verification Requirements.
The current verification requirements are based on best practices for GHG verification and are sufficient to provide a good foundation for a GHG reporting program. However, experience implementing the current requirements has shown the need to clarify a few areas in the existing regulation for program consistency. That includes requirements for how to assess for material misstatement and activities at site visits. The transition to a cap-and-trade program also highlights the need for a third verification statement option that acknowledges the quality of the data when there is a non-conformance that does not lead to a material misstatement and a need to develop a facility emissions number that is the basis for a compliance obligation when the emissions data report does not pass verification. These small additions to the existing verification requirements are needed to support the needs of a cap-and-trade. As such, ARB staff chose not to simply maintain the current verification requirements without making necessary revisions.

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 support the cap- and-trade program. 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 Emission Trading Scheme and California's proposed requirements for the Western Climate Initiative. Given the need for extremely accurate, high quality emissions data, ARB staff has rejected this alternative.

Allow Self-Verification of Emissions Data 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 any misstatement. Staff rejected this alternative 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. Trained, experienced, independent verifiers provide the dispassionate expertise to help assure the accuracy expected by international standards and required to support a program where intangible goods such as greenhouse gas emissions are now a monetized commodity.

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. By requiring the use of third-party verifiers, including the experts already working as verifiers under the current GHG reporting regulation, California is able to remain consistent with existing GHG reporting programs and assure data quality, while creating opportunities for highly skilled positions in the private sector. Under the staff proposal, ARB will continue to provide training and oversight of verifiers, and carry out audits to assure a consistent, fair and robust verification process needed to support the cap-and-trade program. Therefore, given the existing and functioning third-party verification program under the current GHG reporting regulation, ARB staff has rejected this alternative.

Use the U.S. EPA Verification Process.

Staff reviewed the current verification process in the U.S. EPA regulation before proposing that California stay with its existing process of independent, third-party verification. The U.S. EPA regulation contains a verification process that relies on automated routines to screen submitted emissions data reports for inconsistencies and flag data that do not meet certain criteria. Although this process is termed "verification" by U.S. EPA, it is inconsistent with the international standard for verification of GHG emissions data reports. Experience with California's existing regulation has shown that errors are very common in emissions data reports and that third-party verification is important in the submittal of an accurate emissions data report, especially to ensure that all required sources are included in the emissions data report. Having a third-party verifier review each reporting entity's emissions data report ensures a careful and thorough review of all data submitted to ARB. Under the staff proposal, ARB would continue to rely on the international standard of third-party verification to ensure credible and accurate reporting to support the cap-and-trade program. As such, ARB staff has rejected this alternative.

VIII. SUMMARY AND RATIONALE FOR PROPOSED REGULATIONS

The proposed revision of the Regulation for the Mandatory Reporting of Greenhouse Gas (GHG) Emissions for California is necessary to support a California GHG cap-and-trade program and to harmonize with the U.S. Environmental Protection Agency (U.S. EPA) federal mandatory GHG reporting requirements. This section summarizes the requirements and rationale for each provision of the proposed regulations.

Subarticle 1
General Requirements for Greenhouse Gas Reporting

Summary of Section 95100, Table of Contents

This section provides a Table of Contents of the Subarticles and Sections of this article.

Rationale for Section 95100.

This section is necessary to provide an outline of the regulation and assist those subject to the regulation to understand and comply with the all sections applicable to them.

Summary of Section 95100.5, Purpose and Scope.

Summary of Section 95100.5(a).
This section describes the overall purpose of the proposed revised California greenhouse gas reporting regulation, including a brief summary of those subject to reporting, how the regulation is organized, incorporation of the U.S. EPA reporting rule for greenhouse gases, and key terms use in the regulation.

Rationale for Section 95100.5(a).
This section is necessary to provide a general orientation and framework to the regulation so that those subject to reporting understand and comply with the regulation.

Summary of Section 95100.5(b), Organization of Article.
This provision briefly describes each of the five subarticles of the regulation.

Rationale for Section 95100.5(b).
This provision is necessary to ensure that those subject to the regulation understand the structure of, and comply with, the regulation.

Summary of Section 95100.5(c), U.S. EPA GHG Reporting Rule.
This provision describes the specific incorporated U.S. EPA final rules, and dates of promulgation, to be used for the purposes of ARB GHG reporting. Within the proposed regulation, GHG emission estimation and reporting requirements adopted by the U.S. EPA are used as a basis for the proposed ARB reporting requirements.

Rationale for Section 95100.5(c).
The U.S. EPA reporting rule for greenhouse gases is undergoing regular revisions. In order to ensure consistent reporting requirements that will consistently meet ARB program needs, it was necessary to associate our proposed regulation to a specific, fixed version of the U.S. EPA reporting rule. If we did not fix our regulation to a specific date of the U.S. EPA rule, future modifications to the U.S. EPA rule could potentially weaken existing federal requirements. This would create uncertainties for a market program and require time consuming revisions to the ARB regulation in order to restore the stringency needed for our requirements. Tying the ARB regulation to the U.S. EPA regulation adopted as of a certain date minimizes this potential risk.

Summary of Section 95100.5(d), Substitution of Terms and Responsibility.
This provision substitutes the terms "Administrator" and "EPA" with "Executive Officer" and "ARB" respectively. It also clarifies the specific party responsible for reporting.

Rationale for Section 95100.5(d).
Much of the proposed regulation is based on, and refers to, the U.S. EPA greenhouse reporting regulation. Given that the controlling agency for this proposed regulation is the California Air Resources Board, it was necessary to modify the terms within the U.S. EPA regulation text to reflect that fact. The other component of this provision is necessary to clarify which party is responsible for reporting in the situation where the owner and operator of a facility are not identical. The party having operational control of the facility, and not the owner, bears ultimate responsibility for reporting. This provision is necessary to avoid ambiguity regarding who must prepare and submit the GHG report.

Summary of Section 95101, Applicability.

This section of the regulation specifies which facilities and entities are subject to greenhouse gas emissions reporting under the proposed regulation. It also specifies methods for determining applicability, which entities are excluded from reporting, the requirements for demonstrating lack of applicability, and the requirements for ceasing reporting if applicability is no longer met.

Rationale for Section 95101.
The rationales for individual components of this section are provided below. Overall, this section is necessary to specifically inform and identify those industry sectors that are subject to the regulation what conditions trigger reporting, what conditions must be met to no longer be subject to reporting, and what does not need to be reported.

Summary of Section 95101(a), General Applicability.
This provision specifies the types of reporting entities who are subject to reporting, specifies that a report must be submitted by those subject to the regulation for 2011 and subsequent calendar years, and indicates these reports must cover the sources and gases in the regulation that are applicable to the reporting entity. This provision also

clarifies that the regulation applies to entities acting as verification bodies and verifiers of emissions data reports and offset project data reports.

Rationale for Section 95101(a).
This provision is necessary to provide a framework for those who are subject to the requirements of the regulation. The new framework begins with the U.S. EPA regulation, which did not exist when the current ARB regulation was adopted. In general, facilities subject to reporting are the same as those specified in 40 CFR §98.2(a)(1)-(3) of the U.S. EPA regulation, but there are some differences in applicability. This provision is needed to indicate that entities both within and beyond the U.S. EPA reporting requirements would be required to report to ARB under the proposed regulation. The provision indicates that there are some modifications to the federal rule applied to those within its scope, and that there are some reporting entities for that are beyond the scope of the U.S. EPA rule that would be required to report in California. These specific modifications are provided within section 95101. This provision is also necessary to inform verifiers and verification bodies that the regulation applies not only to those subject to GHG reporting, but also to those entities (verification bodies and third party verifiers) that will verify submitted reports and offset project data reports.

Summary of Section 95101(b), Calculating GHG Emissions Relative to Reporting Thresholds. Some industrial sectors are required to report based on their annual emissions of CO_2e. This provision specifies the methods that must be used in computing CO_2e emissions for the purpose of determining if a facility exceeds 10,000 metric tons of CO_2e per year. The provision references the methods provided in 40 CFR §98.2(b)-(g). Modifications to the requirements of 40 CFR §98.2(b)-(g) are provided to: a) change the threshold to 10,000 metric tons of CO_2e and an aggregate maximum heat capacity of 12 mmBtu/hr or greater, b) include biomass emissions in the threshold determination, and, c) include emissions from geothermal generating units and hydrogen fuel cells in the threshold determination.

Rationale for Section 95101(b).
This provision is needed to establish the threshold for GHG reporting for sectors subject to a threshold under the terms of the federal regulation. The threshold of 10,000 metric tons of CO_2e is established because of the need to monitor compliance with the cap-and-trade rule and to monitor emissions leakage below the cap-and-trade applicability threshold of 25,000 metric tons of CO_2e, consistent with the decision of Western Climate Initiative partners. The provision is also needed to indicate how a reporting entity subject to a reporting threshold will determine whether its emissions exceed the threshold, including which types of emissions to count in assessing whether the threshold is exceeded.

Summary of Section 95101(b)(1).
This provision indicates that facilities with stationary combustion emissions should count those emissions in assessing whether the reporting threshold is exceeded. Thresholds of 10,000 metric tons of CO_2e and 12 mmBtu are established.

Rationale for Section 95101(b)(1).
A threshold of 10,000 metric tons of CO_2e is established because of the need to monitor emissions leakage below the cap-and-trade applicability threshold of 25,000 metric tons of CO_2e, consistent with the design decision of California and other WCI Partner jurisdictions. The additional heat input capacity threshold of 12mmBtu/hr or greater is established to provide reporters an easy means of assessing whether the emissions threshold may be exceeded, as U.S. EPA does in its regulation. Twelve mmBtu/hr is 40 percent of the U.S. EPA threshold of 30 mmBtu/hr, just as 10,000 metric tons of CO_2e is 40 percent of 25,000 metric tons of CO_2e. A facility with stationary combustions must meet both thresholds to be subject to the regulation.

Summary of Section 95101(b)(2).
This provision indicates that biomass-derived CO_2 must be counted in assessing whether the reporting threshold has been met.

Rational for Section 95101(b)(2).
This provision is needed to ensure that facilities with significant biomass emissions are included in the reporting program. Biomass fuels are a large and growing portion of fuels used in California, and it is important that growth in their use be monitored, both to assess the effects of the cap-and-trade program on the use of biomass resources and to comply with AB 32 requirements to account for emissions from all electricity consumed in California.

Summary of Section 95101(b)(3).
This provision indicates that geothermal and hydrogen fuel cell emissions are counted in assessing whether the reporting threshold has been met. Both CO_2 and CH_4 count for geothermal sources, and CO_2 counts for hydrogen fuel cells.

Rational for Section 95101(b)(3).
This provision is needed to comply with AB 32 requirements to account for emissions from all electricity consumed in California.

Summary of Section 95101(c), Fuel and CO_2 Suppliers.
This provision specifically identifies which fuel and CO_2 suppliers are subject to reporting under the regulation.

Rationale for Section 95101(c).
This provision is needed to establish the threshold for GHG reporting for fuel and CO_2 suppliers subject to a threshold under the terms of the federal regulation. In some cases, a threshold of 10,000 metric tons of CO_2e is established because of the need to monitor compliance with the cap-and-trade rule and to monitor emissions leakage below the cap-and-trade applicability threshold of 25,000 metric tons of CO_2e. The provision is also needed to indicate how a reporting entity subject to a reporting threshold will determine whether its emissions exceed the threshold, including which types of emissions to count in assessing whether the threshold is exceeded.

Summary for Section 95101(c)(1).
This provision requires position holders and refineries that supply a volume of fossil and/or biomass-derived fuel that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(1).
This provision is necessary for position holders and refineries to provide information on fuel supplied to support the determination of their compliance obligations under the ARB cap-and-trade program. Position holders were chosen as the point of regulation for the majority of fuel supplied in California because they are the only entities that can accurately account for the final destination of the fuel. Refineries as specified in section 95121 of the MRR only report fuel supplied to entities not licensed by the California Board of Equalization (BOE), to give a complete account for all fuel combusted in California. Position holders and refineries already report this information to the BOE.

Summary for Section 95101(c)(2).
This provision requires enterers that supply a volume of fossil and/or biomass-derived fuel that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(2).
This provision is necessary to include enterers above the reporting threshold in the reporting requirements, so that they can provide information on fuel supplied to support the determination of their compliance obligations under the ARB cap-and-trade program. Enterers were chosen as a point of regulation because they import fuel into California, and the U.S. EPA MRR does not include domestic imports. Enterers already report this information to the BOE.

Summary for Section 95101(c)(3).
This provision requires producers of biomass-derived fuels that supply a volume of fossil and/or biomass-derived fuel that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(3).
This provision is necessary to track the growth in usage of biomass-derived fuels, to allow ARB to monitor the success of reduction strategies, and to ensure rigorous and constant emissions accounting.

Summary for Section 95101(c)(4).
This provision requires refiners that produce liquefied petroleum gas, without regard to the volume produced, to report.

Rationale for Section 95101(c)(4).
This provision is necessary to include refiners in the reporting requirements for liquefied petroleum gas. Information on liquefied petroleum gas supplied will support the

determination of their compliance obligations under the ARB cap-and-trade program. Refiners already report the majority of the information required to the U.S. EPA MRR, and have no reporting threshold under the U.S. EPA MRR.

Summary for Section 95101(c)(5).
This provision requires operators of interstate pipelines that deliver a volume of fossil and/or biomass-derived fuel that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(5).
This provision is necessary to track fuel deliveries from interstate pipelines, to get an accurate accounting of all natural gas consumed in the state.

Summary for Section 95101(c)(6).
This provision requires California consignees of liquefied petroleum gas that deliver a volume of liquefied petroleum gas that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(6).
This provision is necessary to include consignees of liquefied petroleum gas in the reporting requirements, so that they will provide information on liquefied petroleum gas supplied to support the determination of their compliance obligations under the ARB cap-and-trade program. Consignees were chosen as a point of regulation because they import fuel into California, and the U.S. EPA MRR does not include domestic imports.

Summary for Section 95101(c)(7).
This provision requires local distribution companies that deliver a volume of fossil and/or biomass-derived fuel that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(7).
This provision is necessary to include local distribution companies (LDC) in the reporting requirements, so that they will provide information on natural gas supplied to support the determination of their compliance obligation under the ARB cap-and-trade program. LDCs above the U.S. EPA threshold report almost the same data under the U.S. EPA MRR.

Summary for Section 95101(c)(8).
This provision requires operators of intrastate pipelines that deliver a volume of fossil and/or biomass-derived fuel that when combusted would result in greater than or equal to 10,000 metric tons of CO_2e to report.

Rationale for Section 95101(c)(8).
This provision is necessary to include intrastate pipelines in the reporting requirements, to provide information on natural gas supplied to support the determination of their

compliance obligation under the ARB cap-and-trade program. It is also necessary to give a complete accounting of all natural gas delivered in California.

Summary for Section 95101(c)(9).
This provision requires natural gas liquid fractionators that produce liquefied petroleum gas, without regard to the volume produced, to report.

Rationale for Section 95191(c)(9).
This provision is necessary to include natural gas liquid fractionators in the reporting requirements, so that they will provide information on liquefied petroleum gas supplied to support the determination of their compliance obligations under the ARB cap-and-trade program. Natural gas liquid fractionators already report the majority of the information required to the U.S. EPA MRR.

Summary for Section 95101(c)(10).
This provision requires producers of carbon dioxide to report under the regulation without regard to the volume produced. It also requires importers of carbon dioxide to report if annual imports into California are 10,000 metric tons or more.

Rationale for Section 95101(c)(10).
This provision is necessary to include CO_2 producers and importers in the reporting requirements, so that they will provide information on liquefied petroleum gas supplied to support the determination of their compliance obligations under the ARB cap-and-trade program. CO_2 producers and importers, above the U.S. EPA threshold, already report the majority of the information required to the U.S. EPA MRR.

Summary of Section 95101(d), Electric Power Entities.
This provision identifies the electric power entities that are subject to reporting under the regulation, including electricity importers and exporters, retail providers, the California Department of Water Resources (DWR), the Western Area Power Administration (WAPA), and Bonneville Power Administration (BPA).

Rationale for Section 95101(d).
This provision is necessary to include certain electric power entities in the reporting requirements, so that they will provide information needed to support the determination of their compliance obligations under the ARB cap-and-trade program.

BPA, as an asset-controlling supplier, would report basic information necessary to support ARB's calculation of a supplier-specific emission factor. Electricity importers, including BPA, need this factor to calculate and report GHG emissions associated with BPA system power imported into California.

Two multi-jurisdictional retail providers would report wholesale purchases, sales, and facility information necessary to support ARB's calculation of their supplier-specific emission factors. Electricity importers need these factors to calculate and report GHG emissions associated with their system power imported into California. Reporting by electricity exporters, which include retail providers and marketers, is necessary to support the ARB GHG Inventory.

All retail providers, in addition to those who import or export electricity, would report retail sales to support the calculation of free allowances under the ARB cap-and-trade program. Reporting by WAPA and DWR of electricity consumed to operate federal and state water projects (pump loads) is necessary to support Scoping Plan Implementation measures for water efficiency and conservation.

Summary of Section 95101(e), Petroleum and Natural Gas Systems.
This provision specifies a reporting requirement for operators of petroleum and natural gas systems and identifies facility types within this sector where reporting is required.

Rationale for Section 95101(e).
Previously, petroleum and natural gas system operators were only required to report stationary combustion emissions. This revised draft regulation adds requirements for the reporting of vented, process, and fugitive emissions – these additional emissions represent a large fraction of facility total emissions for the source categories covered here. U.S. EPA (USEPA TSD W 2009) estimates indicate that process emissions for the petroleum and natural gas system source categories covered by this rule represent approximately 70% to 100% of total source emissions.

Summary of Section 95101(e)(1), Offshore Facilities.
This provision sets forth reporting requirements for offshore petroleum and natural gas production facilities.

Rationale for Section 95101(e)(1).
This provision is necessary because process, vented and fugitive emissions represent a large and major fraction of GHG emissions for this sector (90%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. Only stationary combustion emissions are covered by the current reporting regulation.

Summary of Section 95101(e)(2), Onshore Facilities.
This provision sets forth reporting requirements for onshore petroleum and natural gas production facilities.

Rationale for Section 95101(e)(2).
This provision is necessary because process, vented and fugitive emissions represent a large and major fraction of GHG emissions for this sector (69%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. Only stationary combustion emissions are covered by the current reporting regulation.

Summary of Section 95101(e)(3), Natural Gas Processing Plants.
This provision sets forth reporting requirements for onshore natural gas processing plants.

Rationale for Section 95101(e)(3).
This provision is necessary because process, vented and fugitive emissions represent a large and major fraction of GHG emissions for this sector (95%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. Only stationary combustion emissions are covered by the current reporting regulation.

Summary of Section 95101(e)(4), Onshore Natural Gas Compression Facilities.
This provision sets forth reporting requirements for onshore natural gas transmission compression facilities.

Rationale for Section 95101(e)(4).
This provision is necessary because process, vented and fugitive emissions represent a large and major fraction of GHG emissions for this sector (89%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. Only stationary combustion emissions are covered by the current reporting regulation.

Summary of Section 95101(e)(5), Underground Natural Gas Storage Facilities.
This provision sets forth reporting requirements for underground natural gas storage facilities.

Rationale for Section 95101(e)(5).
This provision is necessary because process, vented and fugitive emissions represent a large and major fraction of GHG emissions for this sector (84%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. Only stationary combustion emissions are covered by the current reporting regulation.

Summary of Section 95101(e)(6), Liquefied Natural Gas Storage Facilities.
This provision sets forth reporting requirements for liquefied natural gas storage facilities.

Rationale for Section 95101(e)(6).
This provision is necessary because process, vented and fugitive emissions represent a large and major fraction of GHG emissions for this sector (90%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. Only stationary combustion emissions are covered by the current reporting regulation.

Summary of Section 95101(e)(7), Liquefied Natural Gas Import and Export Facilities.
This provision sets forth reporting requirements for liquefied natural gas import and export facilities.

Rationale for Section 95101(e)(7).
This provision is necessary because process, vented and fugitive emissions comprise essentially all the emissions for this sector (100%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. These facilities have not been required to report in the past because any associated combustion emissions were well below the reporting threshold.

Summary of Section 95101(e)(8), Liquefied Natural Gas Distribution Facilities.
This provision sets forth reporting requirements for liquefied natural gas distribution facilities.

Rationale for Section 95101(e)(8).
This provision is necessary because process, vented and fugitive emissions comprise essentially all the emissions for this sector (100%, USEPA TSD W 2009) and the current MRR does not provide methodologies to quantify these emissions. These facilities have not been required to report in the past because any associated combustion emissions were well below the reporting threshold.

Summary of Section 95101(f), Exclusions.
This provision describes the components, facilities, and activities that are not subject to reporting under the regulation.

Rationale for Section 95101(f).
This provision is necessary to inform the specified entities that they are not covered by the regulation. Electricity generating facilities such as wind or solar facilities are not subject to reporting (except as specified) because they generally do not emit GHG emissions. Permitted backup or emergency generators and fire suppression equipment does not need to be reported because emissions from these sources are typically very small, and accurate accounting of the fuel used by these activities can be difficult. Generally, portable equipment is excluded because the emissions are typically small, transient, and captured in other parts of the emission inventory data (such as from fuel suppliers). Certain types of schools are excluded because they are generally very small GHG emitters and to avoid a financial burden on local primary and secondary school districts. The current regulation also exempted hospitals from reporting; these are no longer excluded because they often operate cogeneration units.

Summary of Section 95101(g), Demonstration of Nonapplicability.
For those entities that believe they are not subject to reporting, this provision of the regulation provides ARB with the authority to request and receive information needed to support an entity's claim that it is not subject to reporting.

Rationale for Section 95101(g).
This provision is necessary so that ARB may request information needed to ensure compliance with the regulation and confirm whether an entity is or is not subject to the regulation. Without this section, ARB might be limited in its ability to gather information needed to determine reporting applicability for those not obviously subject to reporting.

Summary of Section 95101(h), Cessation of Reporting.
This provision establishes the criteria that must be met for reporters to cease reporting and verification. In general, the proposed regulation follows the U.S. EPA approach for the cessation of reporting. However, because of the lower ARB reporting threshold of 10,000 tons of CO_2e, this provision includes modifications to the U.S. EPA language to

reflect the difference. It also specifies that a report must be filed for the year the shutdown occurred and for the first full year of non-operation. The provision further clarifies that while facilities that have been shutdown for the entire year do not need to be verified, verification is required for prior emissions data reports.

Rationale for Section 95101(h).
This provision is necessary to provide appropriate flexibility to facilities that lower their emissions below applicable thresholds, or shut down entirely. Facilities with emissions lower than applicable thresholds should be able to cease reporting after a period that demonstrates the lower emissions are not temporary. Facilities that shut down should not be responsible for continued reporting after a report that demonstrates emissions are no longer occurring. In the latter case the expense of verification should also be spared. ARB staff are able to confirm that the shutdown occurred by checking with the local air district.

These provisions vary slightly from the current regulation. Part of the variation is due to the change in reporting threshold. In addition, the current regulation did not directly address the results of a shutdown on emissions reporting. The revised regulation addresses this situation more directly.

Summary of Section 95102, Definitions.

This section defines all key terms used within the regulation that may not be in common usage or which may potentially be ambiguous without a regulatory definition.

Rationale for Section 95102.
This section is necessary to ensure that those subject to the regulation are able to understand and interpret the regulation correctly, and to avoid ambiguity and improve compliance with the regulation. We have attempted to include all key terms used in the regulation, including terms in the previously referenced U.S. EPA regulation, which are usually included without modification to support consistent interpretation of the state and federal regulation.

Summary of Section 95103, Greenhouse Gas Reporting Requirements.

This section specifies the overall greenhouse gas emissions reporting requirements for reporting entities, including clarification on what and how to report, and sets forth deadlines for report and verification statement submittal. It also sets forth the frequency of fuel monitoring, the methods for calculating de minimis emissions, calibrating equipment, and clarifies procedures for changes in methodology.

Rationale for Section 95103.
This section is needed to inform reporting entities of common reporting requirements, and to differentiate between reporting requirements for lower-emitting facilities that are outside the cap-and-trade system and those facilities subject to compliance obligations under the cap-and-trade regulation.

Summary of Section 95103(a), Abbreviated Reporting for Facilities with Emissions Below 25,000 Metric Tons of CO_2e.
This provision allows the use of simplified emission estimation methods and reporting requirements for facilities that emit less than 25,000 metric tons of CO_2e per year. The provision also specifically identifies the information that must be reported by facilities that are able to use this section. It also specifies that suppliers and electric power entities cannot use abbreviated reporting.

Rationale for Section 95103(a).
In the regulatory proposal, the threshold for emissions reporting is 10,000 metric tons of CO_2e per year, which is necessary to provide consistency with the threshold accepted by the other Western Climate Initiative jurisdictions. This threshold includes more reporting entities than the baseline threshold applied by the U.S. EPA regulation, which is 25,000 metric tons. To reduce reporting burdens for facilities that are not subject to the U.S. EPA regulation, but which are subject to the ARB regulation due to the lower 10,000 metric ton threshold, we developed simplified reporting requirements. This approach provides data needed to fully monitor the effects of a cap-and-trade program (including emissions leakage to smaller facilities), while greatly simplifying the reporting requirements for smaller facilities not subject to that program. This provision is designed for operators of facilities. Suppliers are not included here because their reporting requirements under the proposed revised regulation are already relatively simple and/or consistent with existing reporting requirements for tax purposes. Electric power entities are not included here because full and complete reports are needed to account for emissions from imports per AB 32 requirements.

Summary of Section 95103(a)(1).
This provision requires reporting of facility name, and identifying and location information.

Rationale for Section 95103(a)(1).
This information is needed to enable ARB staff to properly identify facilities and their locations, and to enable sorting of emissions data by region or air district.

Summary of Section 95103(a)(2).
This provision requires reporting of total emissions for all stationary combustion units on site, which may be determined through any method specified in the U.S. EPA regulation, including simple application of default emission factors. Emissions are reported by GHG.

Rationale for Section 95103(a)(2).
This provision is needed to provide stationary source emissions totals for the facility, and to inform the facility operator that any method available under the U.S. EPA regulation may be used to estimate these emissions.

Summary of Section 95103(a)(3).
This provision requires reporting of process emissions for the facility, if the facility has one of the process emissions types in the U.S. EPA regulation. (This will occur rarely.) The provision indicates that such emissions are to be estimated using any method available for the type of emissions in the U.S. EPA regulation. The provision also clarifies that if a facility has a Continuous Emissions Monitoring System (CEMS) unit (again expected to be rare for these facilities) the process emissions may be combined with combustion emissions, but that fuel use must still be reported.

Rationale for Section 95103(a)(3).
The provision is needed for the unusual circumstance of process emissions occurring at facilities having relatively low stationary combustion emissions, to ensure the full emissions picture is provided for the facility as a point of comparison to the cap-and-trade threshold, and that ARB is able to fully understand any leakage of process emissions from larger to smaller facilities. Fuel use by fuel type is an important surrogate for emissions and a means of easily checking the reported combustion emissions.

Summary of Section 95103(a)(4).
This provision simply requires the reporting of the methods used to calculate emissions.

Rationale for Section 95103(a)(4).
This provision will enable ARB to understand the basis for the emissions estimate.

Summary of Section 95103(a)(5).
This provision requires the process information (e.g., fuel consumption) used to estimate GHG emissions to be reported, and specifies the units for reporting fuel use. Carbon content and high heat values would also be reported if used to calculate emissions.

Rationale for Section 95103(a)(5).
Process information is needed to ensure the emissions estimates provided can be checked for by ARB reasonableness. Carbon content and high heat values will often not apply, as most facilities reporting under this provision are likely to apply default emission factors.

Summary of Section 95103(a)(6).
This provision requires facilities with on-site electricity generation or cogeneration to provide the information specified in section 95112(a)-(b).

Rationale for Section 95103(a)(6).
This provision is needed so that basic information on electricity generation in California can be maintained. The information requested here is readily available to the reporter.

Summary of Section 95103(a)(7).
This provision requires a signed and date certification statement consistent with U.S. EPA requirements.

Rationale for Section 95103(a)(7).
This provision is needed to ensure a designated party is responsible for the reported information.

Summary of Section 95103(b), Abbreviated Reporting Schedule.
This provision clarifies that abbreviated reports must be submitted by June 1 of each calendar year. It also clarifies that revisions to correct errors must be submitted only if errors exceed 5 percent of total CO_2e emissions or if corrected emissions exceed 25,000 metric tons of CO_2e, in which case, full reporting would be required.

Rationale for Section 95103(b).
Abbreviated reports are due June 1 of each calendar year. Typical reports are due on April 1 of each year. This provision is necessary to provide additional time to entities subject to abbreviated reporting to collect necessary records, perform required estimates, and submit their data. Because these facilities are not directly part of the cap-and-trade program, reporting under the April 1 deadline as required by the other facilities is not necessary. The provision also informs reporting entities when revisions to correct errors need to be submitted.

Summary of Section 95103(c), Abbreviated Reporting Record Keeping.
This provision clarifies that records must still be kept by reporters submitting abbreviated reports, and informs them of which records they must keep. It also provides that facilities submitting abbreviated reports do not have to submit a written GHG Monitoring Plan.

Rationale for Section 95103(c).
This provision is necessary to ensure records are kept in place by the reporter for potential follow-up by ARB, particularly if questions arise about the emission for facilities close to the cap-and-trade threshold. The exclusion of a requirement to develop and maintain a GHG monitoring plan is included here to reduce record-keeping costs for these lower-emitting facilities.

Summary of Section 95103(d), Abbreviated Reporting Verification.
This provision specifies that abbreviated reports do not need to be verified by a third party.

Rationale for Section 95103(d).
Because abbreviated reports are not used for cap-and-trade or to establish compliance obligations, the cost of third party verification of the data to ensure accuracy is not justified. This provision is necessary to inform facilities that they do not have verification requirements.

Summary of Section 95103(e), Reporting Deadlines.
This provision specifies deadlines of April 1 and June 1 for annual emissions reporting.

Rationale for Section 95103(e).
This provision is needed to ensure reports are completed when needed by ARB. The April 1 deadline applies to most reporters; it is one day later than the U.S. EPA deadline, which falls on a State holiday. The June 1 deadline applies to electric power entities and abbreviated emission reports, both of which are not tied to the federal reporting obligation. The later date responds to many comments at and following the March 23, 2010 workshop, which asked for a later deadline to enable electricity transactions data to be properly compiled after it becomes available to electric power entities from outside parties. The later deadline for importers responds to many comments at and following the ARB March 23, 2010, workshop discussing the regulatory proposal.

Summary of Section 95103(f), Verification Requirement and Deadlines.
This provision specifies deadlines of September 1 and October 1 for third party verification. It also clarifies that reporting entities are as responsible as verification bodies to ensure verification statements are submitted on time.

Rationale for Section 95103(f).
This provision is necessary to ensure emissions data are verified and available for use in the cap-and-trade program by the dates indicated. A five-month period is provided for verification of facility and supplier reports, and a four-month period is provided for verification of electric power entity reports. Meeting these deadlines will enable information needed for implementation of the cap-and-trade program to be available when needed, but should provide enough time to enable verification procedures to be implemented successfully within an overall six-month period (April through September). The provision is also needed to inform reporting entities that late contracting with verification bodies does not alleviate them of the responsibility of ensuring their verification statement is submitted on time. This is necessary to promote compliance with the regulation and ensure that emissions data is verified in time to support the cap-and-trade program.

Summary of Section 95103(g), Non-Submitted/ Non-Verified Emissions Data Report.
This provision specifies that the Executive Officer will develop an assigned emissions level for a reporting entity if it fails to submit an emissions data report, or fails to receive a positive verification statement or qualified positive verification statement by the applicable deadline.

Rationale for Section 95103(g).
A reporting entity that is a covered entity under the cap-and-trade program must have annual verified emission data reports that form the basis of its obligation in the cap-and-trade program. This provision is necessary to inform reporting entities of the process and the criteria to be used by the Executive Officer to calculate an assigned emissions level on the behalf of a reporting entity when it fails to provide its own verified emissions

estimate in time for cap-and-trade needs. The criteria in section 95131(c)(5) provide a best-available but conservative estimate of the reporting entity's emissions while serving as a deterrent to noncompliance with the regulation.

Summary of Section 95103(h), Reporting in 2012.
This provision gives an option to operators and suppliers who may not have had monitoring equipment and procedures in place in 2011 to meet their specific emissions calculation requirements in 2012. The option would specify that operators and suppliers report 2011 emissions using monitoring and calculation methods that are applicable to them from 40 CFR Part 98 (the U.S. EPA regulation). It also specifies that electric power entities must report 2011 electricity transactions (MWh) and emissions (MT of CO_2e) under the full specifications of this article as applicable in 2012.

Rationale for Section 95103(h).
This provision is necessary to recognize that this regulation's monitoring requirements will not be in effect in 2011. It allows facilities and suppliers, most of whom will be reporting to U.S. EPA beginning in 2011, to use the information that they would be assembling for their federal reports to report to ARB. This will assist them in cases where the proposed revised regulation may have required a higher tier of calculation and different monitoring to support it. The option is not applicable to electric power entities, which would not be relying on such monitoring data for their emissions reports.

Summary of Section 95103(i), Calculation and Reporting of *De Minimis* Emissions.
This provision specifies criteria and requirements for estimation and reporting of emissions that may be claimed as *de minimis*. This provision is similar to requirements in the currently approved ARB GHG reporting regulation, but a new sentence specifies that *de minimis* methods must be consistent with methods used to report the same emissions to U.S. EPA. The provision further states that *de minimis* calculations are subject to review by the verification body, and must be included in the emissions data report as separately identified *de minimis* emissions. It also clarifies that biomass-derived CO_2 may be included in the facility total against which *de minimis* is measured.

Rationale for Section 95103(i).
This provision is needed to provide an appropriate measure of flexibility to monitoring and reporting of very small sources, thereby reducing costs. The *de minimis* thresholds are identical to those in the current ARB regulation, up to 3 percent of facility emissions, not to exceed 20,000 metric tons of CO_2e. The provision to limit *de minimis* methods to those methods otherwise available to the reporter under the U.S. EPA regulation, for sources reported to U.S. EPA, is needed to ensure consistency with reporting to U.S. EPA, and as a check on reasonableness for emissions estimation for the sources that are reported to U.S. EPA. (*De minimis* sources not reported to U.S. EPA may be estimated using a method of the operator's choosing.) The provision requiring review by the verification body is meant to ensure that *de minimis* emissions are estimated appropriately. The provision to count biomass-derived fuels within the emissions total against which the *de minimis* thresholds are compared ensures sufficient opportunity for

de minimis emissions estimation at facilities that consume significant quantities of biomass fuels.

Summary of Section 95103(j), Calculating, Reporting, and Verifying Emissions from Biomass Derived Fuels.
This provision specifies that facilities and fuel suppliers must separately report, by fuel type, all biomass-derived fuel CO_2 emissions. If the fuel type is not specifically identified in section 95852.2 of the cap-and-trade regulation the fuel will automatically have a compliance obligation. If the biomass-derived fuel is identified in 95852.2 then it will need to be verified subject to the requirements in 95131(i). Biomass-derived fuel that is unable to be verified under 95131(i) will need to be re-identified as Other-Biomass Derived Fuel and will be subject to a compliance obligation.

Rationale for Section 95103(j).
This provision is required because the biomass-derived fuels identified in section 95852.2 of the cap-and-trade regulation may not have a compliance obligation. To avoid double counting certain biofuels will automatically have a compliance obligation and we need an easy tracking method to add them into the Cap-and-Trade compliance obligation. Other biomass-derived fuels may avoid a compliance obligation and will require verification to substantiate that all requirements in 95852.2 and 95131(i) are met. If the verifier is unable to verify the biogenic origin and the other requirements listed in 95852.2 and 95131(i) then the fuel will not be exempt from a compliance obligation.

Summary of Section 95103(k), Measurement Accuracy Requirement.
This provision specifies that reporting entities with fossil fuel emissions equal to or greater than 25,000 metric tons of CO_2e and others subject to the cap-and-trade regulation must comply with U.S. EPA calibration requirements of $\pm$5 percent measurement accuracy for their measurement devices. It also specifies that for entities with frequent outages, they must notify the Executive Officer of any calibration postponement, which would be subject to the approval of the Executive Officer. This notice would include an explanation of the postponement and the date when the calibration would be completed.

Rationale for Section 95103(k).
This provision is similar to requirements in the current ARB reporting regulation, but applies the U.S. EPA language with slight modification. To support cap-and-trade, it is necessary to ensure that measurements associated with determining GHG emissions be highly accurate. Although the current ARB and U.S. EPA rules share the requirement for fuel measurements to be 95 percent accurate, a provision in the U.S. EPA rule could result in indefinite delays in the calibration of measurement equipment. The additional provision to provide notification and review of delays in calibration of measurement devices in intended to keep ARB staff informed of equipment that has not been calibrated, and provide either a schedule for completing equipment calibration or a demonstration calibration is not needed, if applicable. This provision is necessary to

ensure that ARB is aware of such delays, and if a pattern of delay develops, that the Executive Officer is able to direct that calibrations be carried out.

Summary of Section 95103(l), Weekly Fuel Monitoring.
This provision requires that facility operators monitor fuel measurement equipment and maintain records of its proper operation by recording fuel consumption quantities at least weekly when used for GHG emissions calculations. It also specifies that this monitoring must be part of the GHG Monitoring Plan and that the records of fuel consumption must be sufficient to apply missing data substitution procedures in section 95129 if necessary.

Rationale for Section 95103(l).
This provision is necessary to ensure the proper functioning of monitoring equipment for collection of high quality data and to provide historical data for supporting missing data substitution procedures. Unlike fuel characteristic data, which generally has a range of values by definition, fuel consumption can range anywhere from zero to the maximum potential capacity of the equipment. Therefore, staff believes that missing fuel consumption data must be filled with values that can either be correlated with other measured operational parameters or be based on the actual fuel use values under usual operating conditions.

This provision requires weekly recording of fuel use data (daily data is warranted in some situations, but this would not be required). By recording regularly the amount of fuel consumed, the operator builds a base of data that can be drawn upon if it becomes necessary to substitute for missing data when equipment breaks down. The operator benefits from this active monitoring because the weekly or daily data collected will reduce or eliminate the need for more punitive data substitution in a missing data situation.

Summary of Section 95103(m), Changes in Methodology.
This provision requires, when choices are available, that operators select and retain the same methods year-to-year for reporting emissions data. Different methods can be used following approval by the Executive Officer.

Rationale for Section 95103(m).
This provision is necessary to prevent reporters from choosing different emission calculation methods from year to year, which could intentionally or unintentionally produce distorted or inconsistent consistent GHG data. This would produce uncertainty for cap-and-trade and GHG emission inventory programs, which could reduce the overall confidence in data collected and used by the programs. If a credible and scientifically justifiable argument is made to the Executive Officer for the need to use a different method than that historically used, and the Executive Officer approves the change, then another specified method may be used.

Summary of Section 95103(m)(1), Using Improved Methods.
This provision allows operators to make a permanent change to a higher-tier method to compute emissions.

Rationale for Section 95103(m)(1).
This provision provides an exception so that a permanent change can be made to improve the emissions calculation method without Executive Officer approval. Installation of a CEMS after 2013 is the most likely scenario, and the regulation should not lock in an inferior calculation method.

Summary of Section 95103(m)(2), Temporary Change In Method.
This provision allows operators to temporarily modify their baseline methods, when the modification is needed to acquire data required by the missing data provisions. These missing data provisions (section 95129) come into effect when an operator is unable to collect the information specified in regulation.

Rationale for Section 95103(m)(2).
This provision is necessary because 95103(m) prohibits changes to methods. This provision provides an exception so that a method can temporarily be changed so that other data may be collected, rather than potentially collecting no data at all using the non-functioning method or approach.

Summary of Section 95103(m)(3), Reason for Change.
This provision requires operators to describe why a change in methods is being proposed. The operator must also show the difference in emissions estimates using the existing and proposed method.

Rationale for Section 95103(m)(3).
This provision is required to adequately evaluate the potential benefits and disadvantages of changing methods. The data provided helps the ARB to establish that the proposed change in method is scientifically justified and that it would not artificially alter the emission estimates.

Summary of Section 95103(m)(4), Change at Year End.
This provision encourages operators to change methods only at the start of a new reporting year, and not sometime during the reporting year.

Rationale for Section 95103(m)(4).
This provision is necessary to help prevent the reporting of data using one method for part of the year, and then converting to another method for another part of the year. Using multiple methods through the year would produce inconsistent data and would produce less coherent, more difficult to validate, emission estimates.

Summary of Section 95103(n), Addresses.
This provision provides the mailing address for U.S. mail and package deliveries required by the regulation and substitutes the correct California address for those provided in 40 CFR §98.9.

Rationale for Section 95103(n).
This provision is necessary to inform those entities subject to the regulation of the correct mailing address for items that need to be provided via mail to the ARB. In addition, this address substitutes for the address provided in 40 CFR §98.9, so that items intended for the ARB do not get mailed to the U.S. EPA.

Summary of Section 95104, Emissions Data Report Contents and Mechanism.

Section 95104 of the regulation specifies the primary elements required to be provided in an emissions data report. In general, the requirements mirror those in 40 CFR §98.3(c), with additional qualifications below.

Rationale for Section 95104.
In order to provide for complete and consistent reporting, it is necessary to explicitly specify the contents of data reports and the specific reporting mechanism.

Summary of Section 95104(a), General Contents.
This provision identifies the general contents of an emissions data report, including the items in 40 CFR §98.3(c), ARB identification number, air basin, air district, county and geographic location.

Rationale for Section 95104(a).
This provision is necessary to inform the reporting entity what information needs to be included in the GHG emissions data report. The specified information, both that required by 40 CFR §98.3(c) and in this section, are required to provide unique facility identifying information, emissions information, and other data needed to support both an GHG emission inventory and a cap-and-trade program. If the data was not collected it would not be possible to clearly identify facilities or determine their emissions and other underlying GHG data.

Summary of Section 95104(b), Designated Representative.
This provision specifies that a single point of contact must be identified and provided for GHG reporting.

Rationale for Section 95104(b).
With the previous implementation of the existing ARB regulation for GHG reporting, we allowed an informal self-designation of facility or entity “Managers” who we used as primary contacts for reporting. One of the designated managers would also be responsible for certifying the reported data as accurate and complete. This provision is necessary to improve on this approach and to provide complete transparency and structured accountability by providing a single point of contact for each reporting entity.

These requirements are also based on those of 40 CFR §98.4 and are necessary to harmonize with the U.S. EPA GHG reporting requirements..

Summary of Section 95104(c), Corporate Parent and NAICS Codes.
This provision requires facilities to report their corporate parent and their North American Industry Classification System (NAICS) codes, as required by U.S. EPA in rule amendments promulgated September 22, 2010. Reporters would provide the same information to ARB.

Rationale for Section 95104(c).
This provision is necessary because NAICS codes include critical information needed for classifying industrial sectors and for a variety of cap-and-trade activities such as identifying allowances and benchmarking, and because corporate parent information helps to group and classify reporters as needed for regulatory programs and analysis.

Summary of Section 95104(d), Energy Purchases.
This provision specifies that energy purchase information must be reported, which is beyond the standard U.S. EPA reporting requirements.

Rationale for Section 95104(d).
The requirement to report electricity purchases, steam purchases, and cooling purchases is necessary to formulate a more complete facility GHG emissions footprint for those reporting, to ensure the quality of the reported data, and to potentially reconcile data provided by the user and generator of the energy. It is also needed by ARB to support implementation of the proposed Energy Audits and Co-benefits Regulation.

Summary of Section 95104(e), Reporting Mechanism.
This provision has been maintained from the current ARB GHG reporting regulation and specifies that reporting entities must submit emissions data reports to ARB via the ARB GHG Reporting Tool or another tool approved by the Executive Officer.

Rationale for Section 95104(e).
To ensure orderly and consistent reporting, a common reporting mechanism must be specified for all reporters. This provision is necessary to inform reporting entities how they will submit required reports to ARB.

Summary of Section 95105, Recordkeeping Requirements.

This section describes which records must be maintained by those subject to reporting. The bulk of the recordkeeping requirements are identical to those specified in 40 CFR §98.3(g)-(h) except for the qualifications described below.

Rationale for Section 95105.
This section is necessary to ensure that all reporting entities maintain complete and consistent data records which document measurements, calculations, results, and other

information. The requirements are needed to properly verify reported data, provide a detailed historical record of data and results, and to assist in any auditing or compliance checks of reported data. Rigorous reporting and recordkeeping is a keystone requirement to providing a credible GHG cap-and-trade program.

Summary of Section 95105(a), Duration.
This provision establishes that those with a compliance obligation under the cap-and-trade regulation must maintain records for 10 years. It also requires that those entities who are subject to the proposed ARB reporting regulation, but who do not have a compliance obligation under the cap-and-trade regulation, maintain records for five years.

Rationale for Section 95105(a).
This provision is necessary to clarify how long reporting entities must keep and maintain records. It also ensures that records are maintained for a sufficient period of time so that ARB may verify and audit the records if necessary.

Summary of Section 95105(b), ARB Requests for Records.
This provision clarifies that ARB reporting entities must provide records or other materials that are required for complying with this regulation to ARB within 20 days of a request by ARB.

Rationale for Section 95105(b).
This provision is necessary to ensure compliance with the regulation. In order to provide a proper auditing function, ARB must have timely access to the underlying information that was used to generate emissions estimates or other required data.

Summary of Section 95105(c), GHG Monitoring Plan.
This provision requires that operators complete and maintain a GHG Monitoring Plan which includes key information needed to document and validate reported data. Monitoring plans are only required by those subject to the cap-and-trade regulation, in addition to those who are required to report to U.S. EPA. The monitoring plan must meet the requirements for such plans in the U.S. EPA regulation, and some additional specific requirements listed in this provision.

Rationale for Section 95105(c).
This provision is needed to provide specific direction to operators regarding what information must be collected and maintained in a GHG Monitoring plan, as described below. To reduce costs and complexity, operators not subject to the cap-and-trade regulation or not reporting to U.S. EPA are not required to develop a GHG Monitoring Plan. These operators are excluded from the requirement because it is less critical to have the additional detailed documentation for operators not in a market-based GHG trading system.

Summary of Section 95105(c)(1), Fuel Use Measurement Devices.
This provision requires operators to identify fuel use measurement devices, indicate how they are used in the emissions data report, and include the information in the written GHG Monitoring Plan.

Rationale for Section 95105(c)(1).
This provision is required because fuel use measurement data is one of the primary cornerstones of computing GHG emissions data. If the fuel devices are not clearly identified and their use specified, then the accuracy and completeness of any emissions data could be uncertain.

Summary of Section 95105(c)(2), OEM Documentation.
This provision requires operators to obtain original equipment manufacturer (OEM) or other documentation that specified accuracy, calibration, and calibration data for measurement devices, and include the information in the written GHG Monitoring Plan.

Rationale for Section 95105(c)(2).
This provision is provided so that when GHG data reports are being audited or verified, the specifications for measurement devices are available and included in the GHG Monitoring Plan. Comparison of these specifications against what was actually used or done by the operator helps to confirm the accuracy of the reported data, and compliance with the regulation.

Summary of Section 95105(c)(3), Training.
This provision requires operators to maintain records of training practices, procedures, and materials, and to include this information in the GHG Monitoring Plan.

Rationale for Section 95105(c)(3).
This provision is provided so the ARB and verifiers can use information to help confirm that those subject to reporting have obtained the necessary training and expertise to competently meet the requirements of the regulation.

Summary of Section 95105(c)(4), Fuel Analysis Methodologies.
This provision requires operators to retain the detailed methodologies for fuel analysis used in complying with the regulation, and include these methods in the GHG Monitoring Plan.

Rationale for Section 95105(c)(4).
This provision is required because the methodologies used for fuel analysis are critical to the accuracy of GHG emission estimates. Use of incorrect methodologies can significantly alter emissions, so requiring that the methods be included in the GHG Monitoring Plan provides a mechanism to help confirm that the correct methods were used.

Summary of Section 95106, Confidentiality.

Summary of section 95106(a).
This provision establishes that emissions data submitted to ARB pursuant to the proposed regulation is public information. It also establishes that data reported to the U.S. EPA pursuant to the reporting requirements of the U.S. EPA reporting rule (USEPA MRR 2009) which is considered by U.S. EPA to be non-confidential shall also be treated as public information by ARB.

Rationale for section 95106(a).
This provision is necessary to inform the public of what information is public information and what is confidential. In addition, given that any information released publicly by U.S. EPA would necessarily become public information, this provision is also necessary to provide consistency with the U.S. EPA reporting rule (USEPA MRR 2009).

Summary of section 95106(b).
This provision establishes that information submitted to ARB pursuant to the proposed regulation that does not qualify as emissions data under section 95106(a) may be designated as confidential if it is either a trade secret or otherwise exempt from public disclosure under the California Public Records Act (Government Code section 6250 et seq.), and such requests for confidentiality will be evaluated by ARB in accordance with the procedures of title 17, CCR, sections 91000 to 91022. The proposed regulation does not change the existing language of this provision.

Rationale for section 95106(b).
This provision is necessary to inform the public how information may be designated as confidential and how ARB will assess such designations pursuant to California law.

Summary of Section 95107. Enforcement.

This section proposes the penalties and consequences of not complying with these regulations. These provisions include penalties pursuant to Health & Safety Code (H&SC) section 38580.

Summary of section 95107(a).
This provision establishes that the failure to submit a required report, including a verification statement, emissions data report, or other record, or the submittal of a late, incomplete, or inaccurate report is considered a separate violation for each day or portion thereof that the report remains unsubmitted, incomplete, or inaccurate.

Rationale for section 95107(a).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. It is necessary to ensure compliance with the regulation and to deter the submission of incomplete or inaccurate reports, as well as to ensure the correction of mistakes as soon as possible. The section also clarifies that "inaccurate" relates to the level of reproducibility of a test or measurement method.

This provision also greatly revises the currently adopted version of section 95107(a) (ARB MRR 2007), which included the "knowing submission of false information, with intent to deceive" as a separate violation. This revision replaces the "knowing, with intent to deceive" standard of liability with a strict liability standard and is necessary to align with WCI requirements and with other ARB environmental regulations. As noted by the WCI in its *Response to Stakeholder Comments and Final Draft Essential Requirements for Mandatory Reporting* (WCI Response to Comments 2009, page 15), strict liability is the normal standard for the imposition of civil liability in environmental regulatory programs. In fact, AB 32's enforcement provisions expressly incorporate existing strict liability enforcement statutes such as H&SC sections 42400 and 42402 without any statutory language indicating an intent to require a higher, narrower standard of 'knowing' or 'intent to deceive' in every instance. Other ARB environmental regulations, including the Low Carbon Fuel Standard (Title 17, CCR, section 95484(e)) and the Airborne Toxic Control Measure for Auxiliary Diesel Engines Operated on Ocean-Going Vessels At-Berth in a California Port (Title 17, CCR, section 93118.3(h)), use the normal strict liability standard. Stakeholders have raised the same concerns addressed in the WCI Response to Comments 2009 with ARB. In order to ensure consistent enforcement with other ARB environmental regulations, and in accordance with the WCI, this provision has replaced the "knowing submission of false information, with intent to deceive" standard of liability with a strict liability standard.

<u>Summary of section 95107(b)</u>.
This provision establishes that each day, or portion thereof, a regulated party does not comply with a requirement of the proposed regulation is considered a separate violation.

<u>Rationale for section 95107(b)</u>.
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. It is authorized by H&SC section 38580(b)(3) and is necessary in this instance to ensure compliance with the regulation, as well as to encourage the correction of mistakes as soon as possible. This provision is also necessary to provide consistency with 40 C.F.R. §98.8 (U.S. EPA MRR 2009). This provision revises the currently adopted version of section 95107(b) (ARB MRR 2007). The requirements of the currently adopted version of section 95107(b) are now included in the revised section 95107(a) as described above.

<u>Summary of section 95107(c)</u>.
This provision specifies that where a regulated party fails to report the metric tons of carbon dioxide equivalent (CO_2e) in its emissions data report as required by the regulation, each metric ton of CO_2e emitted but not reported is a separate violation.

<u>Rationale for section 95107(c)</u>.
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. The proposed revisions are necessary to ensure accurate and stringent emissions data in order to support a cap-and-trade program, and this violation is designed to ensure that reporting entities accurately report

their GHG emissions to ARB and that the number of violations directly reflects the amount of CO_2e emissions. A metric ton was selected as the essential unit of violation for unreported emissions because metric tons are the basic unit both for reporting emissions and for allocations under the proposed cap-and-trade regulation. By using metric tons, the number of violations will remain proportional to emissions, which is in keeping with the statute's overall intent to reduce emissions. In addition, existing enforcement statutes direct ARB to consider, when determining administrative penalties, the "extent of harm caused by the violation," and the "nature and persistence of the violation." (H&SC sections 42410(f) and 42403.5((b)(1)(2)). This provision makes specific that the "extent of harm" and the "nature" of a failure to report will be analyzed, for penalty purposes, in terms of metric tons. This provision is also consistent with similar violations in the proposed cap-and-trade regulation, as well as the proposed Renewable Electricity Standard regulation (*see* proposed Title 17, CCR, section 97009).

Summary of section 95107(d).
This provision specifies that each failure to comply with the methods in the proposed regulation for measuring, collecting, recording, and preserving information needed for the calculation of emissions constitutes a separate violation of the proposed regulation.

Rationale for section 95107(d).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. This provision is necessary to inform the public what constitutes a violation of the proposed regulation, and to ensure that reporting entities will utilize the methods required by the regulation. This provision is also necessary to provide consistency with 40 C.F.R. §98.8 (U.S. EPA MRR 2009).

Summary of section 95107(e).
This provision proposes the revocation or modification of an Executive Order issued pursuant to the proposed regulation as one consequence of violating the proposed regulation.

Rationale for section 95107(e).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. This provision is necessary to inform the public of what constitutes a sanction for noncompliance with the regulation.

Summary of section 95107(f).
This provision clarifies that the violation of any condition of an Executive Order issued pursuant to the proposed regulation constitutes a separate violation of the proposed regulation.

Rationale for section 95107(f).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. This provision is necessary to inform the public of what constitutes a violation of the proposed regulation.

Summary of section 95107(g).
This provision merely restates existing law regarding penalties.

Rationale for section 95107(g).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. This provision is necessary to inform the public of what the penalties will be for noncompliance with the regulation and to direct the public to the appropriate statute to determine the penalties.

Summary of section 95107(h).
This provision merely restates existing law regarding injunctions.

Rationale for section 95107(h).
This provision provides clarification as to the basis, processes and procedures that would apply in an enforcement proceeding. This provision is necessary to inform the public of what the penalties will be for noncompliance with the regulation and to direct the public to the appropriate statute regarding injunctions.

Summary of Section 95108, Severability.

Summary of Section 95108.
This section ensures that if one provision of the regulations is declared invalid by a court or other authority, the remaining provisions will remain in full force and effect.

Rationale for Section 95108.
This section is necessary to ensure that if ARB has enacted a provision in the proposed regulatory article that is illegal or unconstitutional, the remaining regulatory provisions remain intact.

Summary of Section 95109, Standardized Methods.

Summary of Section 95109(a).
This provision requires entities to use either those standardized methods and materials listed in the U.S. EPA regulation, or another similar method published by an organization listed in 40 CFR §98.7 that is appropriate to the analysis being conducted. The section also provides the option for the characteristics of gaseous fuels to be determined using chromatographic analysis as specified in the U.S. EPA rule. The section also requires all methods used to be documented in the GHG Monitoring Plan that is as required by section 95105(c).

Rationale for Section 95109(a).
This provision is necessary to provide requirements to reporters on the appropriate laboratory methods to be used in determining emissions. It provides limited flexibility to reporters to use methods beyond those specified by U.S. EPA, which will enable regularly updated laboratory methods to be used. The provision that allows gas chromatography to determine fuel characteristics is needed to provide consistency with

specific U.S. EPA requirements. The provision to require that methods be documented in the GHG Monitoring Plan is needed to ensure the verification body can check that appropriate methods were used for the analyses being conducted. The requirements here vary from the very specific and limited requirements in the current regulation, in recognition of the fact that laboratory methods change and reporters need the flexibility to adapt their emissions calculations to such changes.

Summary of Section 95109(b).
This provision allows alternative test methods to those in 95109(a) to be used upon written approval by the Executive Officer based on a demonstration to the satisfaction of the Executive Officer that the alternative methods are equally or more accurate than the methods in 95109(a).

Rationale for Section 95109(b).
This provision will allow reporting entities the option to request approval of alternative test methods that may work more effectively at some individual facilities, based on site-specific situations, or may be more generally usable at a wide range of facilities. Requiring written approval of alternative test methods by the Executive Officer is necessary to ensure that such alternative test methods will provide accurate data.

Subarticle 2
Reporting Requirements and Calculation Methods for Specific Types of Facilities, Suppliers, and Entities

Summary of Section 95110, Cement Production.

This provision specifies the overall greenhouse gas emissions reporting requirements and methods for the cement production industry.

Rationale for Section 95110.
This provision is necessary because these facilities within California can produce significant levels of greenhouse gas emissions. In order to accurately quantify their greenhouse gas emissions it is necessary to fully specify reporting requirements for the cement production sector. The proposed regulation provides consistent and equitable reporting requirements and supports the proposed cap-and-trade program. In addition, this provision substantially harmonizes most ARB reporting requirements with U.S. EPA greenhouse reporting requirements for the sector, which helps to simplify reporting for those subject to the regulation.

Summary of Section 95110(a), CO_2 from Fossil Fuel Combustion.
This provision of the regulation provides specific requirements for estimating CO_2 emissions for the industrial sector.

Rationale for Section 95110(a).
This provision is necessary because it requires facilities subject to this section to apply calculation methods that account for fuel carbon variability, which provides data of

sufficient quality for the cap-and-trade program and consistent with proposed WCI Harmonization Requirements. The requirement also allows the use of Tier 1 estimation methods for de minimis sources and standardized fuels, which helps to simplify the reporting requirements where warranted.

<u>Summary of Section 95110(b), Monitoring, Data, and Records</u>.
This provision requires that monitoring, data, records, and other information collected or reported is consistent with the provisions of the CO_2 combustion method(s) used by the operator in the previous section.

<u>Rationale for Section 95110(b)</u>.
This provision is necessary to ensure complete, accurate, and credible GHG emissions data. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG emissions data reports for accuracy and completeness.

<u>Summary of Section 95110(c), Procedures for Missing Data</u>.
This provision specifies the procedures for the substitution of missing data for this industrial sector.

<u>Rationale for Section 95110(c)</u>.
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for reporting entities to attempt to report using incomplete or false data.

<u>Summary of Section 95110(c)(1), Procedures for Missing Data - Stationary Combustion and CEMS</u>.
This provision identifies the missing data provisions in the regulation that must be followed for stationary combustion sources, and sources using CEMS. The provision refers to section 95129 of the regulation, which specifies these requirements for all combustion and CEMS sources.

<u>Rationale for Section 95110(c)(1)</u>.
This provision is needed to specify how to substitute for missing data for combustion sources or sources using CEMS, consistent with similar provisions applied in the requirements for other industrial sectors. Without this provision, missing data provisions would be ambiguous or unclear to the reporting entity. The specific provisions of section 95129 are addressed in the summary and rationale paragraphs for that section.

<u>Summary of Section 95110(c)(2), Procedures for Missing Data – Carbonate Content of Clinker and Cement Kiln Dust</u>.
This provision applies missing data procedures for instances when clinker and cement kiln dust carbonate content data are missing and a new analysis cannot be undertaken. The provision requires use of maximum data values if less than 80% of required data are available or use of the highest quality assured value recorded during the given data

year, as well as the two previous data years if more than 80% but less than 90% of required data are available.

Rationale for Section 95110(c)(2).
This provision is necessary to provide direction to reporting entities about what to do if they are missing required data for clinker and cement kiln dust carbonate content. If this provision was not included, then inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage compliance, provides a strong incentive to maintain accurate and operational measurement systems, and encourages reporting entities to follow a robust sampling regime that includes backup sample collection.

Summary of Section 95110(c)(3),Procedures for Missing Data – Raw Material Consumption and Clinker Produced.
This provision describes what an operator is required to do when data are missing for raw material consumption or clinker production. The provision requires use of maximum data values if less than 80% of required data are available.

Rationale for Section 95110(c)(3).
This provision is necessary to provide direction to operators about what to do if they are missing required data for raw material consumption or clinker production. If this provision was not included, then inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage compliance and provides a strong incentive to maintain accurate and operational measurement systems.

Summary of Section 95110(c)(4), Procedures for Missing Data - Recordkeeping.
This provision requires operators to document the procedures used for estimates performed using missing data.

Rationale for Section 95110(c)(4).
This provision is necessary to ensure that required calculations are well documented so that the methods used, and the validity and accuracy of those methods, can be confirmed in the verification process.

Summary of Section 95110(d), Additional Data to Support Benchmarking.
This provision requires the reporting of additional data parameters to support benchmarking activities.

Rationale for Section 95110(d).
This provision is needed to allow ARB to collect and calculate data that will serve as the foundation for benchmarking activities. Benchmarking, as part of a cap-and-trade system, helps to protect trade-exposed industries from certain competitive disadvantages. Benchmarking also gives greater value to the most efficient entities, and rewards early actions to reduce emissions.

<u>Summary of Section 95111, Electric Power Entities</u>.

This section specifies the greenhouse gas emissions reporting requirements and additional required information for the following for electric power entities:

- Retail providers and electricity marketers (including WAPA, BPA, DWR, and multi-jurisdictional retail providers) provide information on imported electricity—electricity deliveries and associated emissions.
- BPA, as an asset-controlling supplier, has the option to provide additional information on a voluntary basis.
- Multi-jurisdictional retail providers report wholesale purchases, sales, and facility information.
- Procedures are specified for ARB to calculate emission factors for specified facilities and units associated with imported electricity.
- The default emission factor for electricity from unspecified sources is provided.
- Provisions account for real emissions reductions and assure that reductions from changes in specified resources are real.
- Information is provided by electricity importers for ARB to report those emissions reductions attributable to electricity consumed in California but that do not also reduce net emissions in the total Western Region bulk system power pool.
- Exported electricity is reported by retail providers and marketers.
- Retail providers report retail sales. Verification of retail sales is not necessary if the information is deemed not confidential.
- WAPA and DWR report electricity consumed to operate Federal and State water projects (pump loads), respectively.

<u>Rationale for Section 95111</u>.
Greenhouse gas emissions attributed to electricity consumed in California are nearly equally divided between in-state generation and imported electricity. Imported electricity accounted for 61 million metric tons of CO_2e, slightly more than the estimated 55 million metric tons of CO_2e from in-state electricity generation, as published in the *2008 ARB GHG Inventory* updated May 12, 2010 (ARB CA GHG Inventory for 2000-2008). This reality of the California electricity sector requires imported electricity to be treated similarly to in-state generation.

Of the total greenhouse gas emissions associated with imported electricity, 43 percent was attributed to facilities outside California that are under contract or ownership obligation to serve California customers, referred to as specified sources. The remaining 57 percent was attributed to unspecified sources that contribute to the Western Region power pool. Conditions for reporting specified sources of electricity are necessary to support California's cap-and-trade program and fundamental to assuring the environmental integrity of the cap.

The electricity sector has unique characteristics that are reflected in the staff proposal. The staff proposal is consistent with AB 32 requirements, the current ARB regulation

(ARB MRR 2007), the proposed electricity sector protocol recommended jointly by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) included as attachment D in the 2007 staff report (ARB ISOR 2007), and the Western Climate Initiative (WCI) *Final Essential Requirements of Mandatory Reporting* (WCI ERMR 2009). Staff's proposal incorporates the requirement in AB 32 and the WCI Partner jurisdictions' recommendation that emissions from electricity generated outside the WCI Partner jurisdictions but consumed within them be included in the program (WCI Program Design 2010).

Retail providers and electricity marketers—including WAPA, BPA, DWR, and multi-jurisdictional retail providers—are required to provide information on imported electricity to support the determination of their compliance obligations under the ARB Cap-and-Trade program. BPA, as an asset-controlling supplier, may voluntarily report additional information necessary to support ARB's calculation of a more precise supplier-specific emission factor. Electricity importers, including BPA, need this factor to calculate and report GHG emissions associated with BPA system power imported into California. PacifiCorp and Sierra Pacific Power Company are the two multi-jurisdictional retail providers in California. They report wholesale purchases, sales, and facility information necessary to support ARB's calculation of their supplier-specific emission factors. Electricity importers, including PacifiCorp and Sierra Pacific Power Company, need these factors to calculate and report GHG emissions associated with their system power imported into California.

The reporting of exported electricity by electricity exporters, which include retail providers and marketers, is needed to support the ARB GHG Inventory. All retail providers, in addition to those who import or export electricity, report retail sales to support the calculation of free allowances under the ARB cap-and-trade program. WAPA and DWR report electricity consumed to operate Federal and State water projects (pump loads), respectively, to support Scoping Plan Implementation measures for water efficiency and conservation.

<u>Summary of Section 95111(a), General Requirements and Content for GHG Emissions Data Reports for Electricity Importers and Exporters</u>.
The list of required elements for electric power entity greenhouse gas (GHG) reports is provided in subsection 95111(a). Emissions, in metric tons of CO_2e, are to be reported in addition to the continuing requirement to report electricity deliveries in megawatt-hours. Electricity importers and exporters must report deliveries and associated GHG emissions from imported electricity from unspecified and specified sources, imported electricity from asset-controlling suppliers and multi-jurisdictional retail providers, exported electricity, and electricity from generating and cogeneration units in California. Provisions for reporting electricity wheeled through California, electricity deliveries under exchange agreements, and electricity generating and cogeneration units outside of California are included in section 95111(a). Documentation requirements to support verification also are included.

Rationale for Section 95111(a).
This provision is necessary to meet the statutory mandate of AB 32, which requires the reporting of all electricity generated and consumed in California. Electric power entities report GHG emissions associated with imported electricity to determine the quantity of allowances each must hold for compliance with the ARB cap-and-trade program. Electricity deliveries are the basis for the emissions calculations and are reported to support independent verification, auditing and enforcement by the ARB, statewide data quality assurance by the ARB in collaboration with the CEC and CPUC, and the ARB GHG inventory.

Exported electricity is reported for information purposes only. In 2008 and 2009, reported exports were a very small portion of reported imports, only two to three percent. It is anticipated that as ARB links with other WCI jurisdictions, this information will be needed for regional tracking and data quality assurance. Exports are not reported to calculate cap-and-trade compliance obligations nor free allocations. The concept of an optional border adjustment or free allocations for exports has been discussed by the WCI Electricity Committee.

Exchange agreements are reported consistent with requirements to report imported and exported electricity. ARB has determined that netting is not allowed, since imported electricity is consumed in California and exported electricity is first generated from California sources. Imported electricity is reported to determine the compliance obligation. Electricity generated in California and exported must also pay its cap-and-trade compliance obligation, so that future linked jurisdictions can be assured that electricity exported from California has met its compliance obligation. Electricity cannot pass through California without paying its compliance obligation unless it is wheeled through California. This means the electricity does not have a final point of delivery in California, i.e., it does not sink or serve load in California. Allowing netting of imports and exports for exchange agreements would have the affect of allowing electricity that is consumed and generated in California to avoid its compliance obligation, which is counter to the requirements of AB 32.

Electricity importers and exporters report electricity wheeled through California as a data quality assurance measure.

Summary of Section 95111(b), Calculating GHG Emissions.
Required methods for calculating GHG emissions associated with imported electricity are provided in section 95111(b) and divided into four types of sources:

1. unspecified sources
2. specified facilities or units
3. specified asset-controlling suppliers
4. specified multi-jurisdictional retail providers.

Electric power entities will use the equations provided in this provision, which include ARB emission factors. ARB will calculate and publish on its Mandatory Reporting Program website the needed emission factors for each of the four types of sources for use by reporting entities. ARB will calculate the emission factors based on a preferred ranking of data sources described in each subsection. ARB will publish and update these emission factors prior to the reporting deadline.

Rationale for Section 95111(b).
This provision is necessary to calculate and report associated GHG emissions (MT of CO_2e) for imported electricity (MWh) consumed in California, including line losses, as required by AB 32. A two percent transmission loss factor is established to meet the requirement in AB 32 to include line losses when they are not already included in reported deliveries or made up from generation sources located in California. ARB will calculate and publish the needed emission factors in order to assure rigorous and consistent accounting. To provide transparency, it is necessary to demonstrate how ARB will calculate the needed emission factors.

Summary of Section 95111(b)(1), Calculating GHG Emissions from Unspecified Sources.
This provision sets forth the methods for calculating GHG emissions associated with unspecified sources of imported electricity.

Rationale for Section 95111(b)(1).
This provision is necessary for electric power entities to report GHG emissions associated with electricity from unspecified sources. This provision is based on coordinated efforts by ARB, CEC, CPUC, and the WCI. These efforts and the reasoning behind them are explained below.

The default emission factor for electricity from unspecified sources will be re-calculated using the Final WCI Default Emission Factor Calculator created by CPUC staff, vetted through the WCI Electricity Team, and adopted by the WCI Partners (WCI Default Emission Factor Calculator 2010). Based on an interim prototype version of the WCI calculator, ARB staff is currently proposing a default emission factor equal to the average emission factor for years 2006, 2007, and 2008. Marginal facility capacity factors are less than 60 percent and 2 percent transmission line losses are included. The resulting default emission factor is 0.435 MT of CO_2e/MWh. This factor is needed for calculating a compliance obligation during the first compliance period on imported electricity reported under section 95111 and for setting the cap under the cap-and-trade program.

It is anticipated that ARB, in future rulemakings, will reset this emission factor for reporting purposes before each compliance period, based on a rolling three year average. This procedure will accommodate the interests of stakeholders to smooth out variations from year to year and have a factor in advance of each compliance period. Stakeholders also have recommended that the default factor should be updated periodically, so reported emissions reflect cleaner emitting marginal generation over time.

The WCI Electricity Team has posted two versions of the default emission factor calculator on the WCI website. The “lite” version contains the calculator worksheet and its data table. The full version contains the underlying data that were used to create the data table for the calculator, and an embedded document from the original Energy Information Administration files that provides additional information on the data and the codes used to identify fuels and generation technologies.

For electricity that can not be traced back to specified sources, the CPUC and CEC recommended that ARB use the default emission factor of 1,100lbs CO_2/MWh, until a regional tracking system could be developed (ARB ISOR 2007 - Attachment D). The joint recommendation explains that 1,100lbs CO_2/MWh reflects the regional average for the western states and also approximates an emission factor for marginal electricity generation available in the market. To establish a completely transparent, reasonably simple, and sufficiently rigorous method to determine this emission factor to support the cap-and-trade program, CPUC staff developed a prototype default emission calculator which was vetted through stakeholder discussions held by the WCI Electricity Team as well as the Interagency Electricity Working Group comprised of ARB, CPUC, and CEC staff. ARB staff conducted a reporting workshop in March of 2010 at which the calculator was presented to stakeholders and feedback requested.

The default emission factor is calculated as the total emissions divided by the total net generation of all marginal sources and approximates a load duration curve model. Scenario analyses are facilitated by allowing the user to set linked jurisdictions, marginal facility capacity factor, and transmission losses. The calculator was developed using data from the Energy Information Administration reported by the electricity industry including generator types and capacities, quantities of fuel consumed, net generation, and whether the facility is a combined heat and power (CHP) unit. Using this EIA information, the calculator provides default emission factors by assigning facilities to either a marginal or non-marginal category. In cases where staff identified that a facility did not operate the entire year, the nameplate capacity was multiplied by the fraction of the year the facility operated. For facilities comprised of multiple units combusting different fuels and operating under different conditions, the units are separated to allow calculation of a representative capacity factor.

Staff used a capacity factor of 60 percent, consistent with Senate Bill 1368 (SB 1368 2006), which prohibits any load-serving entity from entering into long-term contracts for baseload generation that exceeds a GHG emission performance standard established by the CPUC. SB 1368 defines a baseload facility as a facility with a capacity factor of "at least 60 percent." Therefore, staff established a "marginal" facility as a facility with a capacity factor less than 60 percent. In addition, facilities that are not dispatchable are excluded, such as facilities with must-take contracts such as CHP or facilities that provide energy as-available such as wind and solar. Hydroelectric power was also excluded since it can be claimed as a specified source of electricity under staff’s proposal.

During the *2009 Integrated Energy Policy Report* (CEC IEPR 2009) preparation, CEC staff analyzed data and determined the 2006, 2007, and 2008 data years are representative for high, medium and low hydroelectricity generation years. ARB staff based the default emission factor for reporting imported unspecified electricity on the average for these three years, consistent with the methodology for setting the cap under the cap-and-trade program.

Summary of Section 95111(b)(2), Calculating GHG Emissions from Specified Facilities or Units.
Required methods for calculation of GHG emissions associated with sources of imported electricity from specified facilities or units are provided in section 95111(b)(2). Electric power entities must use the equation provided, which includes ARB emission factors. ARB will calculate and publish on its Mandatory Reporting Program website the needed emission factors for each specified facility or unit that is registered by electric power entities with ARB *a priori*. ARB will calculate the emission factors for each registered facility or unit based on a preferred ranking of data sources described in section 95111(b)(2). Given the expected timing of available data, staff anticipate that the facility or unit-specific emission factors will be based on data from the year immediately prior to the data year. ARB will publish and update these emission factors with sufficient time for reporting entities to incorporate into their calculations before the reporting deadline.

Rationale for Section 95111(b)(2).
This provision is necessary to allow electric power entities to calculate and report GHG emissions (MT of CO_2e) for imported electricity (MWh) associated with facilities or units that are identified by ownership share or in written contracts as electricity designated to serve California load. It is also necessary to demonstrate how ARB will calculate and publish the needed emission factors, and to assure rigorous and consistent accounting.

Summary of Section 95111(b)(3), Calculating GHG Emissions for Imported Electricity from Specified Asset-Controlling Suppliers.
This provision establishes the required methods for calculating GHG emissions associated with sources of imported electricity from specified asset-controlling suppliers. BPA, reporting to ARB as a marketer, and other electricity importers who procure BPA system power, must use the BPA system power emission factor calculated and published by ARB. BPA has the option of accepting the ARB calculated emission factor based on the method specified in this section or voluntarily providing additional specified data to support a more refined calculation.

Rationale for Section 95111(b)(3).
This provision is necessary to allow electric power entities to calculate and report GHG emissions (MT of CO_2e) associated with imported electricity (MWh), primarily hydroelectricity, from the BPA system power pool. The BPA system power emission factor will be less than the unspecified source default emission factor; and therefore, must be reported as a specified source to accurately account for GHG emissions. The reasoning for allowing a less precise calculation for a BPA system power emission

factor is that ARB staff anticipates the more precise data will not make a significant change to the emission factor since BPA only purchases unspecified power, some of which is fossil-based power, to balance its hydroelectric system. Unspecified power purchases have been reported as approximately 10 percent of total system sales (MWh) in 2008 and 2009. The default emission factor for BPA system power may need to be adjusted upward, depending on the extent to which BPA sells hydroelectric power only in the Pacific Northwest and the power sold into California carries a greater percentage of the unspecified balancing power.

Summary of Section 95111(b)(4), Calculating GHG Emissions for Imported Electricity from Specified Multi-jurisdictional Retail Providers.
This provision sets forth the required methods for calculating GHG emissions associated with sources of imported electricity from specified multi-jurisdictional retail providers. The two multi-jurisdictional utilities that serve California, PacifiCorp and Sierra Pacific Power Company, will use their respective system power pool emission factors calculated and published by ARB to report GHG emissions associated with their imported electricity. ARB will calculate their respective emission factors based on additional data required in section 95111(d) as well as GHG data they report to U.S. EPA and data they report to the EIA. The emission factors will be posted on the ARB Mandatory Reporting website.

Rationale for Section 95111(b)(4).
This provision is necessary to allow reporting entities to calculate and report GHG emissions (MT of CO_2e) associated with imported electricity (MWh) from the system power pools of PacifiCorp and Sierra Pacific Power Company, which are integrated utilities and are recognized by the ARB as asset-controlling suppliers. ARB staff anticipate that the system power emission factors are significantly higher than the default emission factor provided for unspecified sources of electricity; and therefore, they must be reported as specified sources to accurately account for GHG emissions.

Summary of Section 95111(c), Greenhouse Gas Emissions Data Report: Additional Requirements for Retail Providers, excluding Multi-jurisdictional Retail Providers.
Retail providers will continue to report retail sales to the ARB. Retail sales will be published on ARB's website and subject to ARB audit and enforcement, but will not require independent verification. Retail providers who are also importers of electricity must identify and claim specified imported electricity from those facilities in which they have an ownership share or contract. This provision clarifies that imported electricity from these sources cannot be claimed as unspecified power. In addition, California's share of electricity from high-emitting facilities that is sold outside of California, is reported. Retail providers who are also importers of electricity must report electricity imported on their behalf to serve their load.

Rationale for Section 95111(c).
Retail sales are needed to support the cap-and-trade program in calculating free allocations of allowances. It is not necessary to require verification of retail sales, since it will be the only information required for the many retail providers who are neither

importers nor exporters of electricity. Since information on electricity transactions between sources and sinks inside California is no longer needed to support the cap-and-trade program, many retail providers will only report retail sales. Accuracy of reported retail sales continues to be important, as free allocations will be calculated according to a method that will transition to a retail sales basis. Data quality will be protected by making the data public on ARB's mandatory reporting program website and subject to ARB audit and enforcement.

In addition, California's share of electricity from high-emitting facilities that is sold outside of California is reported for two reasons. First, this is needed as a data quality check on reported imported electricity. Second, it is critical to support ARB analysis of emissions reductions attributable to electricity consumed in California that do not also reduce net emissions in the total western region bulk system power pool.

Continuing from the current ARB requirement (ARB MRR 2007), retail providers who are also importers of electricity, report electricity imported on their behalf to serve their load as a data quality check to assure all imported electricity is reported to ARB. This requirement has been discontinued for retail providers who are not electricity importers, to keep their reporting obligation limited to retail sales only.

Summary of Section 95111(d), Greenhouse Gas Emissions Data Report: Additional Requirements for Multi-Jurisdictional Retail Providers.
Under staff's proposal, the two multi-jurisdictional retail providers in California, PacifiCorp and Sierra Pacific Power Company, continue to report the same information as required under the current ARB mandatory reporting program (ARB MRR 2007) with two exceptions. First, they must now report associated GHG emissions with their electricity transactions, consistent with the proposed requirement for other retail providers. Second, multi-jurisdictional retail providers are no longer required to submit and verify facility-specific GHG reports to ARB for out-of-state facilities under their operational control. Instead, ARB will accept U.S. EPA GHG reports (USEPA MRR 2009-2010) for these facilities. In cases where their facilities may not be required to report to U.S. EPA, ARB will accept Energy Information Administration data from form EIA-860, "Annual Electric Generator Report," and form EIA-923, "Power Plant Operations Report."

Multi-jurisdictional retail providers must continue to report wholesale purchases, sales, and facility information to support ARB calculation of a supplier-specific emission factor. They must use this factor when calculating and reporting GHG emissions associated with their imported electricity.

Rationale for Section 95111(d).
This provision is necessary to support the determination of compliance obligations under the ARB cap-and-trade program for multi-jurisdictional retail providers and for other electricity importers that procure system power from either PacifiCorp or Sierra Pacific Power Company and import it into California.

Summary of Section 95111(e), Greenhouse Gas Emissions Data Report: Additional Requirements for WAPA and DWR.
This provision requires DWR and WAPA to report:

- Individual and total pump loads from WAPA Central Valley Project, MWh.
- Individual and total pump loads from DWR State Water Project, MWh.
- Imported electricity, MWh and MT of CO_2e.
- Exported electricity, MWh and MT of CO_2e.
- Retail sales of electricity to end-users, MWh.

Rationale for Section 95111(e).
The purpose of collecting the data is provided as the rationale in the table below.

Required Data	**Purpose**	**New or Continuing Requirement**
Individual and total pump loads from WAPA Central Valley Project, MWh	ARB analysis of water conservation and efficiency measures in Scoping Plan	New
Individual and total pump loads from DWR State Water Project, MWh	ARB analysis of water conservation and efficiency measures in Scoping Plan	Continuing
Imported electricity, MWh and MT CO_2e	Calculate Cap-and-Trade compliance obligation and support ARB GHG Inventory	MWh—Continuing MT of CO_2e —New
Exported electricity, MWh and MT CO_2e	Support ARB GHG Inventory	MWh—Continuing MT of CO_2e —New
Retail sales of electricity to end-users, MWh	Calculate possible Cap-and-Trade free allocation to retail providers and inform analyses for Renewable Electricity Standard Program	Continuing

Summary of Section 95111(f), Greenhouse Gas Emissions Data Report: Additional Requirements for Asset-Controlling Suppliers.
ARB will assign a system emission factor for Bonneville Power Administration (BPA) system power, for multi-jurisdictional retail providers, and for asset-controlling suppliers with a system emission factor greater than 1100 lbs CO_2e/MWh.

Bonneville Power Administration supplies primarily hydroelectric power from their system to California, supplemented by wholesale purchases of unspecified electricity to operate their system. BPA and other electric power entities that import BPA system power into California must use BPA's system emission factor calculated by ARB and published on the ARB Mandatory Reporting website. As specified in section 95111(b), ARB will set this emission factor equal to 20 percent of the default emission factor for electricity from unspecified sources, or base the factor on a more refined calculation from a previously verified GHG emissions data report submitted on a voluntary basis to ARB that meets the additional requirements for asset-controlling suppliers required under the current ARB MRR (ARB MRR 2007) or under this proposal pursuant to section 95111(f).

Other asset controlling suppliers import electricity into California and sell their system power to other electric power entities that import electricity into California. When the estimated emission factor for these suppliers is greater than 1100 lbs CO_2e/MWh, approximately the equivalent of the emission performance standard established by the CPUC and CEC for long term power contracts, the associated emission factor published by ARB must be used to calculate GHG emissions. This includes multi-jurisdictional retail providers.

Rationale for Section 95111(f).
This provision is necessary to support the determination of compliance obligations for the ARB cap-and-trade program for (1) BPA, who imports electricity into California, and for (2) other electricity importers that procure system power from BPA and import it into California. The additional reporting requirements to support calculation of a system emission factor for multi-jurisdictional retail providers are provided in section 95111(d) for clarity.

Staff is proposing that asset-controlling suppliers—other than BPA, PacifiCorp, and Sierra Pacific Power Company—that may import electricity directly into California or supply it to other electric power entities that then import it into California report the additional information under this section so that GHG emissions are accurately reported. Without this information, the imported electricity may be incorrectly reported from unspecified sources and associated with the lower emission factor intended for cleaner, dispatchable, marginal resources which are typically fueled by natural gas.

No electric power entities have requested a system power emission factor from ARB and met the voluntary reporting requirements in the current version of the ARB Mandatory Reporting regulation, which was designed for suppliers with primarily renewable energy facilities in their fleets or suppliers with a limited quantity of unspecified wholesale purchases used to supplement their fleet generation (ARB MRR 2007). Due to lack of interest from electric power entities and staff concern about the potential for resource shuffling to undermine the environmental integrity of the cap-and-trade program, this previous reporting provision is not included in staff's proposal. Resource shuffling is discussed in more detail in the rationale for section 95111(g).

Summary of Section 95111(g), Requirements for Claims of Specified Sources of Imported Electricity and Associated Emissions.
This section sets forth specific reporting requirements to adequately track the validity of claims for lower GHG emission resources. In addition, reporting requirements are included to track expected resource shuffling and shifting resource investment that will occur outside the regulatory authority of the ARB and result in no net emission reductions in the western region. This provision also establishes a process for electricity importers to register their specified sources and suppliers with ARB and receive specified emission factors for different types of electricity generating resources.

Rationale for Section 95111(g).
This section is necessary for ARB to support the environmental integrity of the California cap-and-trade program through accurate and complete GHG emissions reporting associated with imported electricity, within ARB's regulatory authority. In addition, ARB needs information to determine the extent to which resource shuffling and shifting resource investment in the western region bulk system power pool results in increased, decreased, or no net change in GHG emissions in the western region.

ARB is considering additional provisions that would clarify how GHG emissions from specified sources will be reported. In this proposal, accounting conventions are specified to limit financial incentives to change the resource mix for imported electricity in ways that merely shift GHG emissions from California to other jurisdictions, consistent with the intent of the current ARB regulation (ARB MRR 2007) and the *WCI Final Essential Requirements of Mandatory Reporting* (WCI ERMR 2009).

Renewable energy credits (RECs) cannot be used in GHG reporting. This is consistent with the intent of the California cap-and-trade program and the WCI cap-and-trade program (WCI RECs Accounting 2008, WCI RECs Announcement 2010) to provide a smooth transition to a future federal source-based program. A smooth transition requires that RECs from California renewable energy facilities do not have lesser value than RECs from out-of-state facilities, simply due to GHG attribution from the California cap-and-trade program.

Summary of Section 95111(g)(1), Registration of Specified Sources and Suppliers.
This provision requires electricity importers to register specified sources and suppliers and report associated GHG emissions with ARB.

Rationale for Section 95111(g)(1).
This provision is necessary to assure accurate tracking of imported electricity and associated emissions from specified sources and suppliers.

Summary of Section 95111(g)(2), Emission Factors.
The provision sets forth the requirement to use source-specific emission factors calculated by ARB and posted to the ARB Mandatory Reporting website.

Rationale for Section 95111(g)(2).
This provision is necessary to assure accurate tracking of imported electricity and associated emissions from specified sources and suppliers.

Summary of Section 95111(g)(3), Owned Sources.
This provision requires electricity importers to report imported electricity as specified imports when they have ownership in the facility or unit.

Rationale for Section 95111(g)(3).
This provision is necessary to clarify that electricity imported from these sources cannot be reported as unspecified and receive the default emission factor.

Summary of Section 95111(g)(4), Delivery Tracking Conditions Required for Specified Electricity Imports.
This provision sets forth the required conditions for tracking deliveries of specified imported electricity.

Rationale for Section 95111(g)(4).
This provision is necessary to assure accurate tracking of imported electricity and associated emissions from specified sources and suppliers.

Summary of Section 95111(g)(5), High GHG-Emitting Facilities or Units.
This provision contains the requirements for reporting California's share of out-of-state electricity generation that is sold outside California and not imported.

Rationale for Section 95111(g)(5).
This provision is necessary to provide information for ARB to determine the extent to which resource shuffling and shifting resource investment in the western region bulk system power pool results in increased, decreased, or no net change in GHG emissions in the western region.

Summary of Section 95111(g)(6), Low GHG-Emitting, Existing, Fully Committed Resources: Nuclear and Large Hydroelectric Resources.
This provision establishes the accounting conventions for reporting imported electricity from nuclear and large hydroelectric facilities.

Rationale for Section 95111(g)(6).
This provision is necessary to provide reasonable limitations on resource shuffling and to provide information for ARB to determine the extent to which resource shuffling and shifting resource investment in the western region bulk system power pool results in increased, decreased, or no net change in GHG emissions in the western region. This provision is consistent with the intent of the current ARB reporting requirements (ARB MRR 2007) and the WCI reporting requirements (WCI ERMR 2009).

Summary of Section 95111(g)(7), Substitute Electricity.
This provision sets forth the methods for reporting substitute electricity.

Rationale for Section 95111(g)(7).
This provision is necessary to assure accurate tracking of imported electricity and associated emissions from specified sources and suppliers.

Summary of Section 95112, Electricity Generation and Cogeneration.

This section specifies the overall greenhouse gas emissions reporting requirements and methods for electricity generation facilities and cogeneration facilities.

Rationale for Section 95112.
This section is necessary to complete the California energy generation inventory, to provide consistent and equitable reporting requirements, to support greenhouse gas cap-and-trade programs, and to harmonize with U.S. EPA reporting requirements. The introductory paragraph of section 95112 unifies the two different sections in the U.S. EPA rule (Subparts C & D of 40 CFR 98) that cover electricity generating units (EGU). The additional California-specific reporting requirements apply to all units that generate electricity, notwithstanding which U.S. EPA rule section is applicable.

Summary of Section 95112(a), Basic Information for EGUs.
This provision requires the reporting of basic information about EGUs that is essential for California's energy generation inventory and verification of emissions report. The information includes generation capacity, power generation, fuel consumption, emissions of individual greenhouse gases in metric tons, fuel characteristic data, electricity consumed on-site, and electricity sales.

Rationale for Section 95112(a).
This provision is necessary to meet AB 32 requirements for complete reporting of this sector, as well as to monitor these units for cap-and-trade. U.S. EPA's bifurcation of this sector into Part 75 and non-Part 75 creates anomalies because Part 75 units are not required to report some information important to our knowledge of electricity generation in California. To ensure complete, accurate, and credible GHG emissions data, it is required to include comprehensive data collection and reporting. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness.

Summary of Section 95112(b), Basic Information for Cogeneration Units.
This provision requires the operators of electricity generation and cogeneration units to report basic information about cogeneration unit that is essential for California's energy generation inventory and verification of emissions report. In addition to reporting the basic information required by section 95112(a), operators must also report information on cogeneration technology, useful thermal output, thermal energy purchases, and supplemental firing.

Rationale for Section 95112(b).
This provision is necessary to meet AB 32 requirements for complete reporting of this sector, as well as to monitor these units for cap-and-trade. This information will also support cap-and-trade benchmarking and the energy efficiency and co-benefits regulation. To ensure complete, accurate, and credible GHG emissions data, it is required to include comprehensive data collection and reporting. This requirement for

data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness.

Summary of Section 95112(c), CO_2 from Fossil Fuel Combustion.
This provision establishes the method operators must use for estimating CO_2 emissions for combustion emissions from this industrial sector. The provision refers to section 95115 of the regulation, which specifies on the basis of fuel type and unit size which U.S. EPA methods may be selected for calculating emissions of CO_2 from combustion.

Rationale for Section 95112(c).
This provision is needed to provide data of sufficient quality for the cap-and-trade program and consistent with combustion emissions methods required in other industrial sectors. The limitations in section 95115 on selection of an appropriate calculation method are designed to account for fuel carbon variability, which will ensure accurate emissions estimation for combustion, the largest and most important source of overall emissions.

Summary of Section 95112(d), Monitoring, Data, and Records.
This provision requires that monitoring, data, records, and the other information collected or reported are consistent with the provisions of the CO_2 combustion method(s) used by the reporting entity in the previous section.

Rationale for Section 95112(d).
This provision is needed to ensure complete and accurate GHG combustion emissions data are collected by the reporting entity and retained for verification purposes. Because it will help ensure that data are properly collected and that errors can be corrected, the provision is critical for the credibility of the information that becomes the basis of emissions trading.

Summary of Section 95112(e), Biomass Emissions for Units Reporting Under 40 CFR Part 75.
This provision requires operators of 40 CFR Part 75 EGUs to report consumption of biomass-derived fuels and the biogenic portion of their CO_2 emissions.

Rationale for Section 95112(e).
This provision is necessary for determining the compliance obligation of 40 CFR Part 75 units under the cap-and-trade regulation. The U.S. EPA rule does not require operators of Part 75 units to report biogenic portion of CO_2 emissions, which does not have a compliance obligation in cap-and-trade, separately from fossil-based emissions. Reporting of biomass-derived fuel consumption and biogenic CO_2 emissions is essential for cap-and-trade and is needed to ensure consistency with WCI design recommendations.

Summary of Section 95112(f), CO_2 and CH_4 Emissions from Geothermal Facilities.
This provision retains reporting requirements for geothermal facilities from the current California GHG reporting regulation. It requires reporting of CO_2 and CH_4 emissions

using source-specific emission factors derived from an ARB approved measurement plan.

Rationale for Section 95112(f).
This provision is necessary to meet AB 32 requirements for complete reporting of emissions for the electricity sector. Geothermal processes release a substantial amount of CO_2 and CH_4. 40% of the geothermal facilities that reported CO_2 emissions to ARB in 2009 and 2010 indicated that their annual facility emissions are greater than 100,000 metric tons of CO_2.

Although CH_4 emissions reporting is not required by the current California regulation, information provided by geothermal facilities staff and published literature indicate that CH_4 emissions from geothermal sources can also be significant. Many geothermal facilities are already measuring CH_4 emissions as a part of their periodic emission monitoring plan. The additional reporting of CH_4 emissions is consistent with the AB 32 mandate.

This provision requires operators to calculate emissions using source specific emission factors derived from an ARB-approved measurement plan. In the proposed rule, the operator no longer has the option of using default emission factor for GHG reporting. Analysis conducted by ARB staff showed that the current default emission factor is neither conservative nor representative of the measured emissions from the various geothermal reservoirs in California. Because all geothermal operators are either already reporting using source specific emission factors, or making plans for obtaining source specific emission factors in 2010 and beyond, this change in requirement is expected to have little impacts on geothermal facilities' reporting efforts.

Summary of Section 95112(g), Hydrogen Fuel Cells.
This provision requires the reporting of basic information about stationary hydrogen fuel cell EGUs. Operators must report their generation capacity, power generation, fuel/feedstock consumption, provider of fuel/feedstock, and basic cogeneration information if applicable.

Rationale for Section 95112(g).
This provision is necessary to meet AB 32 requirements for complete reporting of this sector. Stationary hydrogen fuel cells emit CO_2 emissions from the hydrogen production process, and depending on the source of the fuel/feedstock, the CO_2 emissions can either be fossil-based or biomass-based. Most existing fuel cells in California are experimental and too small to report on their own (except as part of a facility with larger stationary combustion units), but larger fuel cell units likely to exceed reporting thresholds are in the planning stages.

Summary of Section 95112(h), Missing Data Substitution Procedures.
This provision specifies the procedures for the substitution of missing data for this industrial sector.

Rationale for Section 95112(h).
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for reporters to attempt to report using incomplete or false data.

Summary of Section 95113, Petroleum Refineries.

This section specifies GHG reporting requirements for petroleum refining facilities.

Rationale for Section 95113.
This section is necessary because petroleum refineries represent a significant source of GHG emissions in California. California refineries have been reporting their GHG emissions to ARB for the past two years. Section 95113 harmonizes with GHG reporting requirements found in the U.S. EPA Mandatory Reporting Rule and provides cap-and-trade quality data for GHG emissions associated with this important source.

Summary of Section 95113(a), CO_2 from Fossil Fuel Combustion.
This provision sets forth the reporting requirements for combustion emissions.

Rationale for Section 95113(a).
This provision is necessary to ensure that operators report CO_2 combustion emissions using methods designed to produce cap-and-trade quality data while allowing the use of a Tier 1 methodology for de minimis sources and certain standardized fuels. This provision also is needed to simplify reporting requirements.

Summary of Section 95113(b), Monitoring, Data and Records.
This provision harmonizes monitoring, data and records requirements with the provisions for reporting of GHG emissions from this sector. This section requires that operators meet applicable requirements for monitoring, missing data procedures, data reporting and records retention.

Rationale for Section 95113(b).
This provision is necessary to detail the requirements for monitoring GHG emissions, the data that reporters are required to retain, and methods for replacing missing data. It also ensures an accurate verification, which is one of the cornerstones of an effective GHG reporting program.

Summary of Section 95113(c), Refinery Fuel Gas Sampling.
This provision establishes a date (January 1, 2013) by which the necessary monitoring equipment and procedures must be in-place to measure daily carbon content of refinery fuel gas.

Rationale for Section 95113(c).
This provision is necessary because refinery fuel gas is a very important fuel used extensively in California refineries. The composition of refinery fuel gas can also be

highly variable. U.S. EPA requires daily sampling for this fuel but allows weekly sampling in situation where the required equipment is not in place. With the exception of two "small" refineries, required equipment and procedures should be in-place at California refineries. This provision is consistent with the WCI Harmonization draft, but an additional year is provided in this provision to allow such equipment to be installed.

Summary of Section 95113(d), Calculating CO_2 from Flares.
This provision establishes reporting requirements and calculation methods for refinery flares. This provision requires that operators use the more stringent of two EPA methods for normal flare operations, while allowing the use of the alternative method for periods of start-up, shut-down and malfunction.

Rationale for Section 95113(d).
This provision is necessary to ensure that emissions from flares are calculated consistently and included in the reporting entities' emissions data reports.

Summary of Section 95113(e), Calculating CO_2 from FCCUs and Fluid Coking.
This provision establishes reporting requirements for FCCU units and Fluid Cokers. The provision removes the U.S. EPA 10,000 barrels/day threshold.

Rationale for Section 95113(e).
This provision is necessary because all refinery based FCCU units and fluid cokers in California are currently required to report combustion and process emissions regardless of rated capacity. Thus, consistent with the WCI Harmonization draft, it was not deemed necessary to provide alternative, less stringent methods for some smaller units.

Summary of Section 95113(f), Calculating CH_4 from Delayed Coking Units.
This provision defines reporting requirements for methane emissions which result when a delayed coker vessel is depressurized prior to coke un-loading. Operators are required to calculate vessel void fraction rather than use a default factor and measure the methane content of coke cutting gases semi-annually rather than use a default value.

Rationale for Section 95113(f).
This provision is necessary because it will produce more accurate and precise emissions estimates.

Summary of Section 95113(g), Uncontrolled Blowdown Systems.
This provision requires that operators use the more stringent U.S. EPA option process vent methodology to calculate emissions from uncontrolled blowdowns.

Rational for Section 95113(g).
This provision is necessary because alternative methodologies such as using a default emissions factor, were not considered sufficiently rigorous for a cap-and-trade program.

Summary of Section 95113(h), Data Reporting Requirements for Flares.
This provision sets forth reporting requirements for emissions from flares.

Rationale for Section 95113(h).
This provision is necessary to align with the modified reporting methods. This change is consistent with the WCI Harmonization draft and ensures emissions from flares are reported.

Summary of Section 95113(i), Data Reporting Requirements for FCCUs and Coking Units.
This provision clarifies that when an operator calculates CO_2 emissions from fluid catalytic cracking units or fluid coking units consistent with section 95115(f), the operator does not have to report data required by 40 CFR §98.256(f)(9).

Rationale for Section 95113(i).
This provision is necessary to align with the modified reporting methods. This change is consistent with the WCI Harmonization draft.

Summary of Section 95113(j), Data Reporting Requirements for Uncontrolled Blowdown Systems.
This provision clarifies that when operators calculate CH_4 emissions from uncontrolled blowdown systems consistent with section 95113(h), the operator must report information for process vents as required by 40 CFR §98.256(l) in lieu of 40 CFR §98.256(m)(2).

Rationale for Section 95113(j).
The provision is necessary to align with the modified reporting methods. This change is consistent with the WCI Harmonization draft.

Summary of Section 95113(k), Records that must be Retained.
This provision establishes additional data retention requirements for process vent emissions which the operator determines are below the reporting threshold.

Rationale for Section 95113(k).
This provision is necessary because these added record retention requirements are required to demonstrate that process vent emissions did not exceed specified thresholds for methane and carbon dioxide content. This is consistent with the WCI Harmonization draft.

Summary of Section 95113(l) Missing Data Substitution Procedures.
This provision establishes missing data substitution procedures.

Rationale for Section 95113(l).
This provision is necessary to provide a strong incentive for operators to generate as complete a data set as possible, while specifying how to generate substitution data in circumstances where data was unavoidably lost.

Summary of Section 95113(l)(1).
This provision directs operators to use the missing data provision contained in section 95115 of this article.

Rationale for Section 95113(l)(1).
This provision is necessary to establish standardized missing data provisions for all operators who use Section 95115 – Stationary Fuel Combustion Sources. The application of these requirements for all operators ensures data consistency across multiple facility types.

Summary of Section 95113(l)(2).
This provision establishes missing data provisions for petroleum refiners when reporting emissions from other Stationary Fuel Combustion Sources.

Rationale for Section 95113(l)(2).
This provision is required to provide petroleum refiners with a standard method for reporting missing data. This provision is designed to incentivize complete collection of required data while providing reporters with a method for replacing missing data when necessary.

Summary of Section 95113(m), Additional Data to Support Benchmarking.
This provision requires the reporting of additional data parameters to support benchmarking activities.

Rationale for Section 95113(m).
This provision is needed to allow ARB to collect and calculate data that will serve as the foundation for benchmarking activities. Benchmarking, as part of a cap-and-trade system, helps to protect trade-exposed industries from certain competitive disadvantages. Benchmarking also gives greater value to the most efficient entities, and rewards early actions to reduce emissions.

Summary of Section 95114, Hydrogen Production.

This provision specifies GHG reporting requirements for hydrogen production facilities associated with petroleum refineries and merchant (standalone) hydrogen production facilities.

Rationale for Section 95114.
This provision is necessary because hydrogen is essential to the production of clean transportation fuels and thus California petroleum refineries require large amounts of hydrogen to meet California's stringent fuel standards. Significant process and combustion CO_2 emissions occur during the production of hydrogen and thus an accurate quantification of these emissions is essential. Section 95114 harmonizes with GHG reporting requirements found in the U.S. EPA Mandatory Reporting Rule and

provides cap-and-trade quality data for GHG emissions associated with this important source.

Summary of Section 95114(a), Definition of Source.
This provision requires GHG reporting for hydrogen production facilities which are operated by California petroleum refineries and merchant, or standalone, hydrogen production plants.

Rationale for Section 95114(a).
This provision is necessary to require GHG reporting for all hydrogen production facilities in California that exceed the reporting threshold – both hydrogen production at hydrogen facilities associated with a petroleum refinery and merchant hydrogen plants.

Summary of Section 95114(b), CO_2 from fossil fuel combustion.
This provision sets forth the reporting requirements for combustion emissions.

Rationale for Section 95114(b).
This provision is necessary to require operators to report CO_2 combustion emissions using methods that are designed to produce cap-and-trade quality while allowing the use of Tier 1 methodology for de minimis sources and certain standardized fuel, and it also is needed to simplify reporting requirements.

Summary of Section 95114(c), Monitoring, Data and Records.
This provision harmonizes monitoring, data and records requirements with the provisions for reporting GHG emissions from this sector. This section requires that operators meet applicable requirements for monitoring, missing data procedures, data reporting and records retention.

Rationale for Section 95114(c).
This provision is necessary to detail the requirements for monitoring GHG emissions, the data that reporters are required to retain, and methods for replacing missing data. It also ensures an accurate verification, which is a cornerstone of an effective GHG reporting program.

Summary of Section 95114(d), CO_2 Process Emissions.
This provision requires the use of weighted average carbon content values for fuel and feedstock consumed at hydrogen production facilities.

Rationale for Section 95114(d).
This provision is necessary because the use of weighted average carbon content values allows operators to determine feedstock and fuel carbon content from a composite sample rather than requiring analysis on a more frequent basis while still retaining the required data quality. For example, four weekly samples might be composited to generate a monthly sample which is then submitted for carbon content analysis. The resulting data will accurately represent the monthly fuel composition while requiring only one analysis instead of four.

Summary of Section 95114(e), Sampling Frequencies.
This provision establishes sampling frequencies for gaseous, liquid and solid fuel and feedstock. It also allows composite sampling for liquid and solid samples, thus significantly decreasing analysis costs.

Rationale for Section 95114(e).
This provision is necessary to reduce analysis frequency while still maintaining high resolution sampling and data quality.

Summary of Section 95114(e)(1).
This provision establishes sampling requirements for gaseous fuels and feedstocks. Reporters must use a weighted average monthly carbon content value derived from daily analysis for gaseous fuels other than natural gas. A single monthly carbon content analysis is required for natural gas.

Rationale for Section 95114(e)(1).
This provision is necessary because composition of non-standard gaseous fuels such as refinery fuel gas is variable and thus a daily sampling regime is required to accurately account for this emissions source.

Summary of Section 95114(e)(2).
This provision establishes sampling requirements for liquid fuels and feedstocks. Reporters must use a weighted average monthly carbon content value derived from monthly analysis of daily composite samples for each liquid fuel or feedstock.

Rationale for Section 95114(e)(2).
This provision is necessary because daily sampling is designed to capture compositional variations of liquid fuels and feedstocks, while use of a composite sample for analysis significantly reduces analytical measurements and still maintains required data quality.

Summary of Section 95114(e)(3).
This provision establishes sampling requirements for solid fuels and feedstocks. Reporters must use a weighted average monthly carbon content value derived from monthly analysis of daily composite samples for each liquid fuel or feedstock.

Rationale for Section 95114(e)(3).
This provision is necessary because daily sampling is designed to capture compositional variations of solid fuels and feedstocks, while use of a composite sample for analysis significantly reduces analytical measurements and still maintains required data quality.

Summary of Section 95114(f), Weighted Average Sampling.
This provision details the arithmetic methodology for calculating weighted averages and details the records which reporting entities must retain.

Rationale for Section 95114(f).
This provision is necessary because the use of high frequency sampling to generate a weighted average fuel or feedstock carbon content value significantly reduces the analytical burden on reporters while still maintaining data quality.

Summary of Section 95114(f)(1).
This provision establishes sampling guidelines for collecting weighted average samples.

Rationale for Section 95114(f)(1).
This provision is necessary to provide data consistency and maintain data quality.

Summary of Section 95114(f)(2).
This provision establishes the mathematical methodology for calculating weighted average values.

Rationale for Section 95114(f)(2).
This provision is necessary to ensure data consistency and reduce reporting errors.

Summary of Section 95114(f)(3).
This provision establishes data retention requirements in cases where composite samples are collected.

Rationale for Section 95114(f)(3).
Data retention requirements are necessary to provide verification of reported emissions.

Summary of Section 95114(g). Data Reporting Requirements.
This provision modifies data reporting requirements to match the modified sampling and reporting frequencies. It also provides operators with a reporting method that avoids double-counting emissions that have been included elsewhere in the facility report.

Rationale for Section 95114(g).
This provision is necessary because an accurate GHG accounting procedure must avoid double-counting of emissions.

Summary of Section 95114(h), Missing Data Substitution Procedures.
This provision establishes missing data substitution procedures.

Rationale for Section 95114(h).
This provision is necessary because these missing data substitution procedures are designed to provide a strong incentive for reporting entities to generate as complete a data set as possible, while specifying how to generate substitution data in circumstances where data was unavoidably lost.

Summary of Section 95114(h)(1).
This provision establishes missing data requirements for refinery related stationary combustion emissions.

Rationale for Section 95114(h)(1).
This provision is necessary because missing data requirements are required to ensure that all reporting entities use the same methodology to report missing data. Consistent missing data requirements for all stationary combustion are necessary to ensure industry wide data consistency.

Summary of Section 95114(h)(2).
This provision establishes missing data requirements for all other GHG data which refinery operators are required to report.

Rationale for Section 95114(h)(2).
This provision is necessary because missing data requirements are necessary to ensure data consistency across all California refineries.

Summary of Section 95115, Stationary Fuel Combustion Sources.

Summary of Section 95115.
This provision specifies greenhouse gas emissions reporting requirements and methods for general stationary fuel combustion sources. This component of the regulation applies to multiple industrial sectors, and includes devices that combust solid, liquid, or gaseous fuels, generally for the purposes of generating steam, producing electricity, providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters. This provision provides common methods for estimating CO_2, CH_4, and N_2O emissions from general stationary fuel combustion sources.

Overall, section 95115 uses the U.S. EPA stationary source combustion methods for GHG emissions as its basis. This approach substantially harmonizes the proposed ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for stationary combustion, which helps to simplify reporting and reduce costs for those subject to the rule. However, in certain cased, modifications to the U.S. EPA baseline requirements are needed to support ARB program needs. The remaining provisions of section 95115 describe these modifications.

Rationale for Section 95115.
This section helps to ensure consistent and accurate reporting across all industry sectors. The section provides consistent calculation methods and equitable reporting requirements, which are needed to support greenhouse gas emission inventory and cap-and-trade programs.

Summary of Section 95115(a), CO_2 from Steam Producing Units.
This provision provides the requirements from estimating CO_2 emissions from combustion units at facilities that produce steam. It provides specific emission estimation requirements based on the fuel burned. Within the U.S. EPA reporting regulation, units that produce steam may use Tier 2 calculation methods for any fuel. This provision allows use of the Tier 2 steam method for municipal solid waste and solid biomass fuels. However, the method may not be used for estimating combustion from high-emitting and variable fossil fuels, such as coal.

Rationale for Section 95115(a).
This provision limits the use of the less accurate Tier 2 steam-based method for certain fossil fuels because the method provided in the U.S. EPA MRR does not provide sufficient accuracy for estimating fossil fuel emissions for sources in a cap-and-trade program. This approach is consistent with the Western Climate Initiative reporting approach for steam generating units. The steam method is acceptable for biomass fuels because they are not included in the cap and trade system. For municipal solid waste (MSW), the method is allowed because MSW is typically a highly variable fuel, so generally there is not a more accurate and reasonable alternative for estimating GHG emissions for MSW combustion.

Summary of Section 95115(b), CEMS CO_2 Monitor.
This provision requires that if a new continuous emissions monitoring system (CEMS) is installed for the purpose quantifying CO_2 emissions, the operator must install a CO_2 monitor for direct CO_2 monitoring. Operators who use O_2 monitors to report CO_2 emissions, and conduct Relative Accuracy Test Audits for the unit, must use the RATA data for CO_2 estimates.

Using CEMS, emissions of CO_2 may be estimated either using instrumentation that directly measures CO_2 concentrations, or using instrumentation that measures oxygen (O_2) concentrations. For fuels with variable carbon content, the CEMS that directly measure CO_2 provide substantially more accurate emission estimates than systems that use oxygen measurements. This is because the use of oxygen-based CEMS requires the use of conversion factors to approximate CO_2 concentrations, rather than providing a direct measurement of the concentrations. Also, the O_2 to CO_2 conversion factors are very generalized by fuel type. The variations of carbon content of solid fuels, in particular, would not be reflected when O_2 monitoring is used. The proposed language does not require retrofitting of existing CEMS systems, but would require new CEMS to include a CO_2 monitor when a flow monitor (required for CO_2 monitoring) is included in the CEMS system.

Rationale for Section 95115(b).
This provision provides improved accuracy and reliability of CO_2 emissions estimates which are needed to support cap-and-trade and other GHG programs. The increased cost to install a CO_2 monitor in comparison to the cost of an O_2 monitor is minor, and the CO_2-based monitor provides significantly improved and reliable emissions data. To reduce potential costs, this provision does not require installation of the new monitor

unless new instrumentation is being installed for other reasons, and it also includes an exclusion for facilities which only consume natural pipeline gas, which can be reasonably estimated using O_2 monitors.

Summary of Section 95115(c), Choice of Tier for Calculating CO_2 Emissions.
This provision provides multiple methods, or Tiers, for estimating GHG emissions for general combustion sources. The application of the Tiers for estimating emissions varies based on the type of fuel used and other factors. Tier 1 allows use of default emission factor and fuels data. Tiers 2 and 3 require sampling and analysis to characterize the fuels burned. Tier 4 requires the use of CEMS. The subsections of this provision, described below, specify which tiers must be used for estimating CO_2 emissions..

Rationale for Section 95115(c).
This provision is included to ensure the highest feasible accuracy for the largest and most important emissions sources, while providing simplified methods where possible, to reduce the costs and complexity of reporting. Where fuels are standardized and have known carbon content, or for *de minimis* emissions, the provision allows use of default emission factors (Tier 1). Heating value analysis (Tier 2) provides accurate emissions estimates for natural gas of pipeline quality, as defined in section 95102. Natural gas is the most common fuel in California, and heating value is usually available from the fuel supplier. Another Tier 2 method is specified for certain solid fuels in steam-producing units. Carbon content analysis (Tier 3) or use of continuous emissions monitoring systems (Tier 4) would be required for fuels that often have variable carbon content, subject to additional limitations in the U.S. EPA rule. This is to ensure the emissions from these fuels are accurately calculated, a necessity especially in a market program.

Summary of Section 95115(c)(1), Selection of Tier 1 or Tier 2 for Specified Fuels.
This provision allows for simplified CO_2 calculation methods for certain common fuels (specified in the regulation), with known and consistent characteristics, and for biomass-derived fuels not subject to a compliance obligation under the cap-and-trade regulation. Tier 1 allows use of default emission factors. Tier 2 requires measured fuel high heat value data for computing CO_2 emissions. This provision also limits the use of these methods to units that do not exceed a rated heat input capacity of 250 mmBtu/hr or less, which depending on the fuel, equates to approximately 125,000 to 200,000 metric tons of CO_2 emissions per year, assuming full annual utilization of 8,760 hours/year.

Rationale for Section 95115(c)(1).
This provision is provided for estimating CO_2 emissions for the fuels specified in Table ES-1 of the regulation. For these fuels, CO_2 emissions can be accurately estimated using default emission factors or default high heat values because the high heat value and carbon content of these standardized fuels has little variation. Therefore, the additional expense and complexity of measuring these parameters is not warranted. For combustion of biomass-derived fuels, not included in the cap-and-trade regulation, the use of Tier 1 or Tier 2 methods is sufficient to adequately characterize facility CO_2

emissions, so the use of higher level tiers is not warranted. Finally, this provision can only be applied to units below the specified size threshold. For very large units, with potentially very large emissions levels, higher accuracy, higher Tier methods are needed to effectively support inventory and cap-and-trade programs.

Summary of Section 95115(c)(2), Selection of Tier 2 for Pipeline Natural Gas and Distillate Fuels.
This provision allows the use of Tier 2 methods for pipeline quality natural gas and distillate fuels (i.e., diesel fuel). The method requires quantification of the high heat value (HHV) of the fuel by either the fuel supplier or the user of the fuel.

Rationale for Section 95115(c)(2).
This provision is included because the use of measured high heat (HHV) data can be used to compute accurate CO_2 emissions estimates for these standardized fuels. However, because of the limited variability which can occur with pipeline natural gas and distillate fuels, the use of Tier 1 methods is not allowed, because it does not require measurement of the fuel characteristics, as Tier 2 does.

Summary of Section 95115(c)(3), Tier Selection for *De Minimis* Emissions.
This provision allows the use of any emission estimation Tier if the reported emissions for the source meet the requirements necessary to be defined as de minimis for the GHG report. Therefore, default emissions factors, HHV data, carbon content data, or CEMS may be used to estimate *de minimis* emissions, unless specifically prohibited by 40 CFR §98.33(b).

Rationale for Section 95115(c)(3).
This provision provides operators flexibility in reporting their *de minims* emissions so they do not have to expend unnecessary resources in order to compute emissions for small, potentially difficulty to quantify, emission sources. Because these sources are, by definition, small relative to the full facility emissions, the necessity for higher quality data is reduced.

Summary of Section 95115(c)(4), Use of Tier 3 and Tier 4 Methods.
This provision specifies that for all other sources subject to section 95115(c) of the regulation, and not specifically excluded in 95115(c)(1)-(3), operators must use either the Tier 3 method or Tier 4 methods. Tier 3 requires measurement of carbon content and Tier 4 requires use of CEMS.

Rationale for Section 95115(c)(4).
This provision is provided to accurately quantify CO_2 emissions from the combustion of variable fuels, or for those operators who already have installed CEMS. For variable fuels such as coal, the use of HHV data does not provide accurate emission estimates. And, if a source already has a properly installed and operating CEMS system, this system provides high quality CO_2 emissions data, so therefore it must be used for emissions estimates.

Summary of Section 95115(d), Source Test Option for N_2O and CH_4.
This provision allows reporters to measure site-specific facility emissions data for nitrous oxide (N_2O) and methane (CH_4) emissions, and use that data to estimate these emissions for the sources that are tested. Source test data would be used instead of default emission factors for estimating emissions. For the proposed regulation, the source test requirements have been strengthened over the current regulation, and it is consistent with the Western Climate Initiative proposal. Emission measurements must be performed in conformance with a facility source test plan submitted to the ARB and approved by the ARB Executive Officer.

Rationale for Section 95115(d).
This provision is included in the proposed regulation for those activities in which stakeholders showed that default emission factors may not accurately represent their actual facility emissions. The current ARB regulation for greenhouse gas reporting now allows the limited use of source test data. The option to use source testing is voluntary; therefore, reporters who prefer to use the other less costly methods within the regulation may do so.

Summary of Section 95115(e), Procedures for Biomass CO_2 Determination.
This provision requires the operator to follow the test procedure in 40 CFR §98.33(e)(3) to determine the biomass portion of CO_2 emissions for the combustion of municipal solid waste or any other fuel for which the biomass fraction is not known.

Rationale for Section 95115(e).
This provision is necessary to ensure the accurate quantification and categorization of fossil fuel and biomass-based CO_2 emissions from fuel combustion when the biomass fraction is not known. This requirement is needed because biomass CO_2 emissions are excluded in determining cap-and-trade compliance obligations, and they must therefore be separately identified and quantified.

Summary of Section 95115(f), Fuel Sampling.
This provision directs facilities which conduct fuel sampling and analysis to gather samples according to the frequencies in the U.S. EPA regulation, with two exceptions. Natural gas outside of pipeline quality would be sampled monthly, rather than semi-annually, and refinery fuel gas would be sampled daily, rather than daily or weekly. For facilities that do not have equipment in place to perform daily analysis of refinery fuel gas, this section requires that equipment be installed, and procedures established to perform daily sampling and analysis no later than January 1, 2013.

Rationale for Section 95115(f).
This provision is provided because WCI analysis found that natural gas outside of pipeline quality (as defined in section 95102), sometimes called field or associated gas, often has carbon content that is 10 to 15 percent different from pipeline gas. Because U.S. EPA has proposed to define natural gas very broadly, it is necessary to impose a

more frequent testing requirement to ensure carbon content is accurately represented in facility emissions The vast majority of facilities consuming natural gas will not be affected by this requirement. In addition refinery fuel gas would be sampled and tested, which is required in the current ARB regulation only for large refineries. Most facilities subject to this requirement of the proposed regulation already have the necessary equipment and procedures in place to meet it. For those that do not, the requirement is necessary to accurately quantify emissions from refinery fuel gas, which is a highly variable fuel. This accuracy is needed to support cap-and-trade and to ensure reporting consistency among similar fuel types. This approach is also consistent with the WCI design recommendations.

Summary of Section 95115(g), Electricity Generating and Cogeneration Units.
This provision requires reporting entities to report electricity generating and cogeneration unit information as required in section 95112, including generating capacity, power generated, thermal output, and other information for electricity generating and cogeneration units.

Rationale for Section 95115(g).
This provision is needed to effectively quantify and characterize the California power industry, as required by AB 32.

Summary of Section 95115(h), Natural Gas Provider.
This provision requires that those subject to the general stationary combustion requirements must report who provided natural gas to their facility, and the customer account number(s) used by the natural gas providers to identify the facility.

Rationale for Section 95115(h).
This provision is needed to provide a more accurate estimate of the GHG compliance obligations for gas suppliers. The collected data can be used to help reconcile the amount of natural gas associated to gas suppliers, providing better estimates, and a more robust cap-and-trade system.

Summary of Section 95115(i), Procedures for Missing Data.
This provision applies missing data procedures, specified and described in section 95129 of the regulation, to ensure data quality is sufficient for GHG inventory and cap-and-trade programs. It specifies what percentage of missing data an operator may use during a year before maximum alternate data must be used to substitute those missing values. In situations where reporters are not able to collect required data, the initial requirement is to complete the missing data with reasonable alternative data, which would tend to reflect the actual operating conditions. However, if substantial quantities of required data are missing, we provide a strong incentive for implementing corrective action. If the data capture rate is less than 80%, then reporters are required to use maximum daily values in place of the missing data.

Rationale for Section 95115(i).
This provision is needed to provide specific methods and protocols for estimating emissions when required data are incomplete. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for reporters to attempt reporting using incomplete data or false data. See the Summary and Rationale for subarticle 3, section 95129, for a full description of the missing data requirements.

Summary of Section 95115(j), Additional Data to Support Benchmarking.
This provision requires the reporting of additional data parameters to support benchmarking activities.

Rationale for Section 95115(j).
This provision is needed to allow ARB to collect and calculate data that will serve as the foundation for benchmarking activities. Benchmarking, as part of a cap-and-trade system, helps to protect trade-exposed industries from certain competitive disadvantages. Benchmarking also gives greater value to the most efficient entities, and rewards early actions to reduce emissions.

Summary of Section 95116, Glass Production.

This section specifies the overall greenhouse gas emissions reporting requirements and methods for the glass production industry.

Rationale for Section 95116.
This section is necessary because these facilities within California can produce significant levels of greenhouse gas emissions. In order to accurately quantify their greenhouse gas emissions, it is necessary to fully specify reporting requirements for the glass production sector. The proposed regulation text provides consistent and equitable reporting requirements and supports greenhouse gas cap-and-trade programs. In addition, this provision substantially harmonizes most ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for the sector, which helps to simplify reporting for those subject to the regulation.

Summary of Section 95116(a), CO_2 from Fossil Fuel Combustion.
This provision provides specific requirements for estimating CO_2 emissions for the industrial sector.

Rationale for Section 95116(a).
This provision is needed to require facilities subject to this part of the regulation to apply calculation methods that account for fuel carbon variability, which provides data of sufficient quality for cap-and-trade programs consistent with proposed WCI Harmonization Requirements. The requirement also allows use of Tier 1 estimation methods for de minimis sources and standardized fuels, which helps to simplify the reporting requirements where warranted.

Summary of Section 95116(b), Monitoring, Data, and Records.
This provision requires that monitoring, data, records, and other information collected or reported is consistent with the provisions of the CO_2 combustion method(s) used by the reporting entity in the previous section.

Rationale for Section 95116(b).
This provision is necessary to ensure complete, accurate, and credible GHG emissions data. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness.

Summary of Section 95116(c), Procedures for Missing Data.
This provision specifies the procedures for the substitution of missing data for this industrial sector.

Rationale for Section 95116(c).
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for reporters to attempt to report using incomplete or false data.

Summary of Section 95116(c)(1), Procedures for Missing Data - Stationary Combustion and CEMS.
This provision identifies the missing data provisions in the regulation that must be followed for stationary combustion sources, and sources using CEMS. The provision refers to section 95129 of the regulation, which specifies these requirements for all combustion and CEMS sources.

Rationale for Section 95116(c)(1).
This provision is needed to specify how to substitute for missing data for combustion sources or sources using CEMS consistent with similar provisions applied in the requirements for other industrial sectors. Without this provision, missing data provisions would be ambiguous or unclear to the reporting entity. The specific provisions of section 95129 are addressed in the summary and rationale paragraphs for that section.

Summary of Section 95116(c)(2), Procedures for Missing Data – Carbonate-Based Raw Materials.
This provision describes what an operator is required to do when data are missing for the amounts of carbonate-based raw materials charged to any continuous glass melting furnace. The provision requires use of maximum data values if less than 80% of required data are available.

Rationale for Section 95116(c)(2).
This provision is necessary to provide direction to operators about what to do if they are missing required data for the amounts of carbonate-based raw materials charged to any continuous glass melting furnace. If this provision was not included, then inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage

compliance and provides a strong incentive to maintain accurate and operational measurement systems.

Summary of Section 95116(c)(3), Procedures for Missing Data - Recordkeeping.
This provision requires that operators document the procedures used for estimates performed using missing data.

Rationale for Section 95116(c)(3).
This provision is necessary to ensure that required calculations are well documented so that the methods used, and the validity and accuracy of those methods, can be confirmed in the verification process.

Summary of Section 95116(d), Additional Data to Support Benchmarking.
This provision requires the reporting of additional data parameters to support benchmarking activities.

Rationale for Section 95116(d).
This provision is needed to allow ARB to collect and calculate data that will serve as the foundation for benchmarking activities. Benchmarking, as part of a cap-and-trade system, helps to protect trade-exposed industries from certain competitive disadvantages. Benchmarking also gives greater value to the most efficient entities, and rewards early actions to reduce emissions.

Summary of Section 95117, Lime Manufacturing.

This section specifies the overall greenhouse gas emissions reporting requirements and methods for the lime manufacturing industry.

Rationale for Section 95117.
This section is necessary because these facilities within California can produce significant levels of greenhouse gas emissions. In order to accurately quantify their greenhouse gas emissions, it is necessary to fully specify reporting requirements for the lime manufacturing sector. The proposed regulation text provides consistent and equitable reporting requirements and supports greenhouse gas cap-and-trade programs. In addition, this provision substantially harmonizes most ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for the sector, which helps to simplify reporting for those subject to the regulation.

Summary of Section 95117(a), CO_2 from Fossil Fuel Combustion.
This provision provides specific requirements for estimating CO_2 emissions for the industrial sector.

Rationale for Section 95117(a).
This provision is necessary because it requires facilities subject to this part of the regulation to apply calculation methods that account for fuel carbon variability, which provides data of sufficient quality for the cap-and-trade program consistent with

proposed WCI Harmonization Requirements. The requirement also allows use of Tier 1 estimation methods for de minimis sources and standardized fuels, which helps to simplify the reporting requirements where warranted.

Summary of Section 95117(b), Monitoring, Data, and Records.
This provision requires that monitoring, data, records, and other information collected or reported is consistent with the provisions of the CO_2 combustion method(s) used by the reporting entity in the previous section.

Rationale for Section 95117(b).
This provision is needed to ensure complete, accurate, and credible GHG emissions data. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness.

Summary of Section 95117(c), Procedures for Missing Data.
This provision specifies the procedures for the substitution of missing data for the lime manufacturing sector.

Rationale for Section 95117(c).
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for operators to attempt to report using incomplete or false data.

Summary of Section 95117(c)(1), Procedures for Missing Data - Stationary Combustion and CEMS.
This provision identifies the missing data provisions in the regulation that must be followed for stationary combustion sources, and sources using CEMS. The provision refers to section 95129 of the regulation, which specifies these requirements for all combustion and CEMS sources.

Rationale for Section 95117(c)(1).
This provision is needed to specify how to substitute for missing data for combustion sources or sources using CEMS, consistent with similar provisions applied in the requirements for other industrial sectors. Without this provision, missing data provisions would be ambiguous or unclear to the reporting entity. The specific provisions of section 95129 are addressed in the summary and rationale paragraphs for that section.

Summary of Section 95117(c)(2), Procedures for Missing Data – CaO and MgO Content.
This provision applies missing data procedures for instances when CaO and MgO content data are missing and a new analysis cannot be undertaken. The provision requires use of maximum data values if less than 80% of required data are available or use of the highest quality assured value recorded during the given data year, as well as

the two previous data years if more than 80% but less than 90% of required data are available.

Rationale for Section 95117(c)(2).
This provision is necessary to provide direction to operators about what to do if they are missing required data for CaO and MgO content. If this provision was not included, then inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage compliance, provides a strong incentive to maintain accurate and operational measurement systems, and encourages reporters to follow a robust sampling regime that includes backup sample collection.

Summary of Section 95117(c)(3),Procedures for Missing Data – Lime Produced and Lime Byproduct/Waste Produced and Sold.
This provision describes what an operator is required to do when data are missing for quantity of lime produced and quantity of lime byproduct/waste produced and sold. The provision requires use of maximum data values if less than 80% of required data are available.

Rationale for Section 95117(c)(3).
This provision is necessary to provide direction to operators about what to do if they are missing required data for quantity of lime produced and quantity of lime byproduct/waste produced and sold. If this provision was not included, then inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage compliance and provides a strong incentive to maintain accurate and operational measurement systems.

Summary of Section 95117(c)(4), Procedures for Missing Data - Recordkeeping.
This provision requires that operators document the procedures used for estimates performed using missing data.

Rationale for Section 95117(c)(4).
This provision is necessary to ensure that required calculations are well documented so that the methods used, and the validity and accuracy of those methods, can be confirmed in the verification process.

Summary of Section 95118, Nitric Acid Production.

This section specifies the overall greenhouse gas emissions reporting requirements and methods for the nitric acid production industry.

Rationale for Section 95118.
This section is necessary because these facilities within California can produce significant levels of greenhouse gas emissions. In order to accurately quantify their greenhouse gas emissions, it is necessary to fully specify reporting requirements for the nitric acid production sector. The proposed regulation text provides consistent and equitable reporting requirements and supports greenhouse gas cap-and-trade

programs. In addition, this provision substantially harmonizes most ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for the sector, which helps to simplify reporting for those subject to the regulation.

Summary of Section 95118(a), CO_2 from Fossil Fuel Combustion.
This provision provides specific requirements for estimating CO_2 emissions for the industrial sector.

Rationale for Section 95118(a).
This provision is necessary because it requires facilities subject to this part of the regulation to apply calculation methods that account for fuel carbon variability, which provides data of sufficient quality for the cap-and-trade program consistent with proposed WCI Harmonization Requirements. The requirement also allows use of Tier 1 estimation methods for de minimis sources and standardized fuels, which helps to simplify the reporting requirements where warranted.

Summary of Section 95118(b), Monitoring, Data, and Records.
This provision requires that monitoring, data, records, and other information collected or reported is consistent with the provisions of the CO_2 combustion method(s) used by the reporting entity in the previous section.

Rationale for Section 95118(b).
This provision is necessary to ensure complete, accurate, and credible GHG emissions data. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness.

Summary of Section 95118(c), Procedures for Missing Data.
This provision specifies the procedures for the substitution of missing data for this industrial sector.

Rationale for Section 95118(c).
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for operators to attempt to report using incomplete or false data.

Summary of Section 95118(c)(1), Procedures for Missing Data - Stationary Combustion and CEMS.
This provision identifies the missing data provisions in the regulation that must be followed for stationary combustion sources, and sources using CEMS. The provision refers to section 95129 of the regulation, which specifies these requirements for all combustion and CEMS sources.

Rationale for Section 95118(c)(1).
This provision is needed to specify how to substitute for missing data for combustion sources or sources using CEMS, consistent with similar provisions applied in the requirements for other industrial sectors. Without this provision, missing data provisions would be ambiguous or unclear to the reporting entity. The specific provisions of section 95129 are addressed in the summary and rationale paragraphs for that section.

Summary of Section 95118(c)(2), Procedures for Missing Data – Nitric Acid Production.
This provision describes what an operator is required to do when data are missing for nitric acid production. The provision requires use of maximum data values if less than 80% of required data are available.

Rationale for Section 95118(c)(2).
This provision is necessary to provide direction to operators about what to do if they are missing required data for nitric acid production. If this provision was not included, then inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage compliance and provides a strong incentive to maintain accurate and operational measurement systems.

Summary of Section 95118(c)(3), Procedures for Missing Data - Recordkeeping.
This provision requires that operators document the procedures used for estimates performed using missing data.

Rationale for Section 95118(c)(3).
This provision is necessary to ensure that required calculations are well documented so that the methods used, and the validity and accuracy of those methods, can be confirmed in the verification process.

Summary of Section 95119, Pulp and Paper Manufacturing.

Summary of Section 95119.
This section specifies the overall greenhouse gas emissions reporting requirements and methods for the pulp and paper industry, which can produce significant levels of greenhouse gas emissions in California.

Rationale for Section 95119.
This provision is included to ensure accurate greenhouse emissions reporting by fully specifying reporting requirements for the pulp and paper manufacturing sector. The proposed regulation text provides consistent and equitable reporting requirements and supports the cap-and-trade program. In addition, the proposed regulation for pulp and paper manufacturing uses the U.S. EPA reporting requirements for pulp and paper manufacturing as its basis. This approach substantially harmonizes the proposed ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for the sector, which simplifies reporting and reduces costs for those subject to the regulation.

Summary of Section 95119(a), CO_2 from Fossil Fuel Combustion.
This provision specifies requirements for estimating CO_2 emissions for combustion emissions from this industrial sector. The provision refers to section 95115 of the regulation, which specifies on the basis of fuel type and unit size which U.S. EPA methods may be selected for calculating emissions of CO_2 from combustion.

Rationale for Section 95119(a).
This provision is needed to provide data quality sufficient for the cap-and-trade program and consistent with combustion emissions methods required in other industrial sectors. The limitations in section 95115 on selection of an appropriate calculation method are designed to account for fuel carbon variability, which will ensure accurate emissions estimation for combustion, the largest and most important source of overall emissions.

Summary of Section 95119(b), Monitoring, Data, and Records.
This provision requires that monitoring, data, records, and the other information collected or reported are consistent with the provisions of the CO_2 combustion method(s) used by the reporting entity in the previous section.

Rationale for Section 95119(b).
This provision is needed to ensure complete and accurate GHG combustion emissions data are collected by the reporting entity and retained for verification purposes. Because it will help ensure that data are properly collected and that errors can be corrected, the provision is critical for the credibility of the information that becomes the basis of emissions trading.

Summary of Section 95119(c), Procedures for Missing Data - General.
This provision specifies the procedures for the substitution of missing data for this industrial sector.

Rationale for Section 95119(c).
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for operators to attempt to report using incomplete or false data.

Summary of Section 95119(c)(1), Procedures for Missing Data - Stationary Combustion and CEMS.
This provision identifies the missing data provisions in the regulation that must be followed for stationary combustion sources, and sources using CEMS. The provision refers to section 95129 of the regulation, which specifies these requirements for all combustion and CEMS sources.

Rationale for Section 95119(c)(1).
This provision is needed to specify how to substitute for missing data for combustion sources or sources using CEMS, consistent with similar provisions applied in the requirements for other industrial sectors. Without this provision, missing data provisions

would be ambiguous or unclear to the reporting entity. The specific provisions of section 95129 are addressed in the summary and rationale paragraphs for that section.

Summary of Section 95119(c)(2), Procedures for Missing Data - Makeup Chemicals. This provision provides direction to operators about what to do if they are missing required data for makeup chemicals (carbonates).

Rationale for Section 95119(c)(2).
This provision is necessary to provide direction to reporters about what to do if they are missing required data for makeup chemicals (carbonates). If this provision were not included, there would be uncertainty for reporters and inconsistent and inaccurate reporting if required data are not available. In addition, the provision helps to encourage compliance by requiring maximum values to be used if less than 80% of required data are available.

Summary of Section 95119(c)(3), Procedures for Missing Data - Recordkeeping. This provision requires that operators document the procedures used for estimates performed using missing data.

Rationale for Section 95119(c)(3).
This provision is necessary to ensure that required calculations are well documented so that the methods used, and the validity and accuracy of those methods, can be confirmed in the verification process.

Summary of Section 95110(d), Additional Data to Support Benchmarking. This provision requires the reporting of additional data parameters to support benchmarking activities.

Rationale for Section 95110(d).
This provision is needed to allow ARB to collect and calculate data that will serve as the foundation for benchmarking activities. Benchmarking, as part of a cap-and-trade system, helps to protect trade-exposed industries from certain competitive disadvantages. Benchmarking also gives greater value to the most efficient entities, and rewards early actions to reduce emissions.

Summary of Section 95120, Iron and Steel Production.

This section specifies the overall greenhouse gas emissions reporting requirements and methods for iron and steel production.

Rationale for Section 95120.
These facilities within California can produce significant levels of greenhouse gas emissions. In order to accurately quantify their greenhouse emissions it is necessary to fully specify reporting requirements for the iron and steel production sector. The proposed regulation text provides consistent and equitable reporting requirements and supports greenhouse gas cap-and-trade programs. In addition, the proposed regulation

for iron and steel manufacturing uses the U.S. EPA reporting requirements for iron and steel as its basis. This approach substantially harmonizes the proposed ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for the sector, which simplifies reporting and reduces costs for those subject to the regulation.

Summary of Section 95120(a), CO_2 from Fossil Fuel Combustion.
This provision specifies requirements for estimating CO_2 emissions for combustion emissions from this industrial sector. The provision refers to section 95115 of the regulation, which specifies on the basis of fuel type and unit size which U.S. EPA methods may be selected for calculating emissions of CO_2 from combustion.

Rationale for Section 95120(a).
This provision is needed to provide data of sufficient quality for the cap-and-trade program and consistent with combustion emissions methods required in other industrial sectors. The limitations in section 95115 on selection of an appropriate calculation method are designed to account for fuel carbon variability, which will ensure accurate emissions estimation for combustion, the largest and most important source of overall emissions.

Summary of Section 95120(b), Monitoring, Data, and Records.
This provision requires that monitoring, data, records, and the other information collected or reported are consistent with the provisions of the CO_2 combustion method(s) used by the operator in the previous section.

Rationale for Section 95120(b).
This provision is needed to ensure complete and accurate GHG combustion emissions data are collected by the reporting entity and retained for verification purposes. Because it will help ensure that data are properly collected and that errors can be corrected, the provision is critical for the credibility of the information that becomes the basis of emissions trading.

Summary of Section 95120(c), Procedures for Missing Data.
This provision specifies the procedures for the substitution of missing data for this industrial sector.

Rationale for Section 95120(c).
This provision is necessary because a primary goal of the reporting program is to collect accurate GHG emissions data in support of cap-and-trade. This helps to ensure that the emissions are not underestimated for the facility, and also makes it unfavorable for operators to attempt to report using incomplete or false data.

Summary of Section 95120(c)(1), Procedures for Missing Data - Stationary Combustion and CEMS.
This provision identifies the missing data provisions in the regulation that must be followed for stationary combustion sources, and sources using CEMS. The provision

refers to section 95129 of the regulation, which specifies these requirements for all combustion and CEMS sources.

Rationale for Section 95120(c)(1).
This provision is needed to specify how to substitute for missing data for combustion sources or sources using CEMS, consistent with similar provisions applied in the requirements for other industrial sectors. Without this provision, missing data provisions would be ambiguous or unclear to the reporting entity. The specific provisions of section 95129 are addressed in the summary and rationale paragraphs for that section.

Summary of Section 95120(c)(2), Procedures for Missing Data – Carbon-Containing Inputs or Outputs.
This provision describes what an operator is required to do when data are missing for the carbon-containing inputs or outputs. The provision requires use of maximum data values if less than 80% of required data are available.

Rationale for Section 95120(c)(2).
This provision is necessary to provide direction to reporters about what to do if they are missing required data for carbon-containing inputs or outputs. If this provision was not included, inconsistent or inaccurate reporting would likely result. In addition, the provision helps to encourage compliance and provides a strong incentive to maintain accurate and operational measurement systems.

Summary of Section 95120(c)(3), Procedures for Missing Data - Recordkeeping.
This provision requires that operators document the procedures used for estimates performed using missing data.

Rationale for Section 95120(c)(3).
This provision is necessary to ensure that required calculations are well documented so that the methods used, and the validity and accuracy of those methods, can be confirmed in the verification process.

Summary of Section 95120(d), Additional Data to Support Benchmarking.
This provision requires the reporting of additional data parameters to support benchmarking activities.

Rationale for Section 95120(d).
This provision is needed to allow ARB to collect and calculate data that will serve as the foundation for benchmarking activities. Benchmarking, as part of a cap-and-trade system, helps to protect trade-exposed industries from certain competitive disadvantages. Benchmarking also gives greater value to the most efficient entities, and rewards early actions to reduce emissions.

Summary of Section 95121, Suppliers of Transportation Fuels.

This section specifies the overall greenhouse gas emissions reporting requirements and methods for suppliers of transportation fuels identified under the applicability section of this regulation. Suppliers are identified as refiners, position holders, enterers and biomass-derived fuel producers for transportation fuels, and refiners for liquefied petroleum gas (LPG).

Rationale for Section 95121.
This section is necessary because these suppliers put on the market fuels that are the single largest source of greenhouse gas emissions in California. In order to accurately quantify their greenhouse gas emissions it is necessary to fully specify reporting requirements for the industry sector. The proposed regulation text provides consistent and equitable reporting requirements and supports greenhouse gas cap-and-trade programs. In addition, the transportation fuels section was written with substantial input from the regulated parties to harmonize most ARB reporting requirements with California Board of Equalization fuel reporting requirements and to facilitate verification of a vast and complex sector, which helps to simplify reporting and verification for those subject to the rule. The LPG section was written to harmonize with the U.S. EPA greenhouse gas reporting requirements. Refiners are required to report the volume and emissions for LPG to be consistent with the cap-and-trade program requirement that suppliers of LPG are covered entities.

Section 95121(a), GHGs to Report.

Summary for Section 95121(a)(1).
This provision specifies that refiners must report CO_2, CH_4, N_2O and CO_2e emissions from the combustion or oxidation of LPG supplied in California.

Rationale for Section 95121(a)(1).
This provision is necessary to clearly define the scope of GHGs that refiners subject to this part of the regulation are required to report. This provision is ensure there is sufficient data for the cap-and-trade program consistent with all other industrial sectors.

Summary for Section 95121(a)(2).
This provision specifies that refiners, position holders, enterers, and producers of biomass-derived fuels will report CO_2, CH_4, N_2O, CO_2 from biomass-derived fuels and CO_2e emissions from the combustion or oxidation of fossil and biomass-derived fuels supplied in California. The fuels required to be reported are listed in Tables MM-1 and MM-2 of 40 CFR Part 98. Fuels are not reported as finished fuels, but as the blendstock plus any additional components.

Rationale for Section 95121(a)(2).
This provision is necessary to clearly define the scope of GHGs that refiners, position holders, enterers, and producers of biomass-derived fuels subject to this part of the regulation are required to report and to provide sufficient data for the cap-and-trade program consistent with all other industrial sectors. In order to facilitate reporting, refiners, position holders and enterers of both fossil and biomass-derived fuels were selected as the point of regulation. These entities were selected as the point of regulation because they currently report almost the same data to the California Board of

Equalization and it facilitates tracking of fuel that leaves the state. Producers of biomass-derived fuels are included to track the growth in usage, to allow ARB to monitor the success of reduction strategies, and ensure rigorous, and constant emissions accounting. To be consistent with the U.S. EPA MRR, the fuels selected for regulation were the fuels listed in 40 CFR 98 Tables MM-1, and MM-1, except that it was determined that Distillate Fuel Oil would be limited to Distillate Fuel Oil #1 and Distillate Fuel Oil #2. The other Distillate Fuel Oils are not significant contributors to transportation emissions in California.

Summary for Section 95121(b), Calculating GHG Emissions.
This provision requires suppliers to apply calculation methods that use fuel specific emission factors that take into account grade and seasonable variability. The use of a Tier 1 or simplified Tier 1 methodology helps to simplify the reporting requirements without sacrificing accuracy. CO_2e emissions are calculated by summing the products of CO_2, CH_4, and N_2O mass emissions and their respective global warming potentials.

Rationale for Section 95121(b).
This provision is necessary to identify the calculation methods required for suppliers subject to this provision of the regulation. Suppliers are required to calculate CO_2, CH_4, N_2O and CO_2 from biomass-derived fuels using a Tier 1 (Volume * High Heat Value * Default Emission Factor) or a simplified Tier 1 (Volume * Default Emission Factor) to calculate emissions. It was determined by staff that the variations in fuel composition were minimal, due to existing fuels regulations, enabling default emission factors to provide the accuracy required for cap and trade. LPG emissions are calculated by summing the emission from its individual components. Biomass-derived CO_2 is not summed for CO_2e emissions because verified or certified biomass-derived fuels will not have a compliance obligation. But CH_4 and N_2O from biomass-derived fuel combustion or oxidation is summed for CO_2e emissions.

Summary of Section 95121(c), Monitoring and QA/QC Requirements.
This provision requires suppliers to follow the monitoring and QA/QC requirements of the U.S. EPA Greenhouse Gas Mandatory Reporting Rule. Position holders are exempted from meter calibration requirements if: (1) the supplier does not operate the meter, (2) the fuel meter is used by other companies that do not share common ownership, or (3) the meter is regulated by the county weights and measures department or equivalent. This provision also specified the standard temperatures and pressures for reporting volumes of each of the regulated fuels.

Rationale for Section 95121(c).
This provision is necessary to ensure complete, accurate, and credible GHG emissions data. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness. Staff believes that all meters used at the terminal rack are certified by the county weights and measures, attesting to their accuracy. All meters at the rack are also used for financial transactions and staff believes that these two factors attest to the accuracy of terminal rack meters, thus relieving reporting entities of the need to prove

calibration. Industry standard temperatures and pressures, that also conform with the U.S. EPA greenhouse gas reporting requirements, are used to standardize and facilitate reporting.

Section 95121(d), Data Reporting Requirements.

Summary of Section 95121(d)(1).
This provision requires position holders to report the annual fuel volumes, in barrels, delivered at the rack for California delivery. The volume reported will be the volumes measured and reported to the position holder by the terminal operator. The position holder will individually report the fuels listed in 40 CFR 98 Tables MM-1 and MM-2 and emissions from the complete combustion or oxidation of those fuels.

Rationale for Section 95121(d)(1).
This provision is necessary to clearly identify the fuels to report and the point of regulation and data collection for position holders.

Summary of Section 95121(d)(2).
This provision requires refiners and position holder who are also terminal operators to report the annual fuel volumes, in barrels, delivered at the rack for California delivery. The volume reported will be the volumes measured at the rack. The position holder or refiner will individually report the fuels listed in 40 CFR 98 Tables MM-1 and MM-2 and emissions from the complete combustion or oxidation of those fuels.

Rationale for Section 95121(d)(2).
This provision is necessary to clearly identify the fuels to report and the point of regulation and data collection for refiners and position holders.

Summary for section 95121(d)(3).
This provision requires refiners to report the annual fuel volumes, in barrels, delivered via the bulk transfer system to entities not licensed by the California Board of Equalization as a fuel supplier. The volumes reported will be the actual volumes delivered based on contracts or metered volumes. The refiner will individually report the fuels listed in 40 CFR 98 Tables MM-1 and MM-2 and emissions from the complete combustion or oxidation of those fuels.

Rationale for Section 95121(d)(3).
This provision is necessary to accurately account for all fuel in the bulk transfer system that is not delivered to a position holder or across the rack.

Summary of Section 95121(d)(4).
This provision requires enterers to report the annual fuel volumes, in barrels, imported into California for delivery. The volume reported will be the volumes reflected in the bill of lading or other shipping documents. The enterer will individually report the fuels listed in 40 CFR 98 Tables MM-1 and MM-2 and emissions from the complete combustion or oxidation of those fuels.

Rationale for Section 95121(d)(4).
This provision is necessary to clearly identify the fuels to report and the point of regulation and data collection for enterers

Summary of Section 95121(d)(5).
This provision requires producers of biomass-derived fuels to report the annual fuel volumes, in barrels, supplied for California delivery. The volume reported will be the volumes measured at a custody transfer meter or listed on a bill of lading. The producer will individually report the fuels listed in 40 CFR 98 Tables MM-1 and MM-2 and emissions from the complete combustion or oxidation of those fuels. If the exact same data is reported under the Low Carbon Fuel Standard regulation the producer will not have to report under this proposed regulation.

Rationale for Section 95121(d)(5).
This provision is necessary to clearly identify the fuels to report and the point of regulation and data collection for biomass-derived fuel producers. Producers of biomass-derived fuels are included to track the growth in usage, to allow us to monitor the success of reduction strategies, and ensure rigorous and constant emissions accounting. If data sufficient for ARB to calculate emission from biomass-derived fuels is reported to ARB via the Low Carbon Fuel Standard regulation, the producers will not have to additionally report under mandatory reporting.

Summary for Section 95121(d)(6).
This provision requires biomass derived-fuel producers to identify the source of any fossil fuels blended with biomass-derived fuels.

Rationale for Section 95121(d)(6).
This provision is necessary to account for all fossil fuels combusted in California. This is to determine if fossil fuels blended by biomass-derived fuel producers are captured by other provisions of this regulation or are unregulated.

Summary for Section 95121(d)(7).
This provision requires refineries to report the volume, in barrels, of liquefied petroleum gas supplied in California, as well as the volumes of the individual components.

Rationale for Section 95121(d)(7).
This provision is necessary to clearly identify that refiners must report LPG volumes.

Summary for Section 95121(d)(8).
This provision requires all fuel suppliers to report CO_2, N_2O, CH_4, CO_2 from biomass-derived fuels, and CO_2e from the complete combustion or oxidation of the supplied fuel. The calculation methodologies are described in 95121(b).

Rationale for Section 95121(d)(8).
This provision is necessary for require reporting of fuel emissions as specified in 95121(b).

Summary for Section 95121(d)(9).
Enterers and biomass-derived fuel producers that deliver fuel to position holders at terminals must identify the recipient of the delivered fuel.

Rationale for Section 95121(d)(9).
This provision is necessary to avoiding double counting of emissions.

Summary of Section 95121(e), Procedures for Missing Data.
This provision sets forth missing data procedures to ensure data quality is sufficient for GHG inventory and cap-and-trade programs. It specifies that suppliers must follow the missing data procedures of the U.S. EPA Greenhouse Gas Mandatory Reporting Rule

Rationale for Section 95121(e).
This provision is necessary to collect accurate GHG emissions data. In situations where reporters are not able to collect required data, reporters are required to use standard billing practices to replace missing data. These methods will provide the most accurate data possible in these situations.

Summary of Section 95122, Suppliers of Natural Gas, Natural Gas Liquids, and Liquefied Petroleum Gas.

This provision specifies the overall greenhouse gas emissions reporting requirements and methods for suppliers of natural gas, natural gas liquids and liquefied petroleum gas identified under the applicability section of this regulation. Natural gas suppliers include public utility gas corporations and publicly owned natural gas utilities which are both considered local distribution companies (LDC) under this regulation, and interstate and intrastate natural gas pipelines. Liquefied petroleum gas (LPG) suppliers are natural gas liquid (NGL) fractionators and LPG consignees that import LPG into California.

Rationale for Section 95122.
These suppliers within California put on the market fuels that when combined are one of the largest sources of greenhouse gas emissions. In order to accurately quantify their greenhouse gas emissions it is necessary to fully specify reporting requirements for this industry sector. The proposed regulation text provides consistent and equitable reporting requirements and supports greenhouse gas cap-and-trade programs. In addition, this provision was written with substantial input from the regulated parties to harmonize most ARB reporting requirements with U.S. EPA greenhouse gas reporting requirements for fuel reporting requirements for the sector and to facilitate verification of a vast and complex sector, which helps to simplify reporting for those subject to the regulation. Natural gas suppliers were expanded to include interstate and intrastate pipelines as sources to get a complete picture of natural gas usage in the state. LPG

consignees were added because the U.S. EPA greenhouse gas reporting requirements did not include domestic LPG importers into California. In order to be consistent with the requirement of the cap-and-trade regulation to include all LPG suppliers in California as covered entities, consignees were added.

Section 95122(a), GHG's to Report.

Summary of Section 95122(a)(1).
This provision adds CH_4, N_2O, and CO_2e emission to the CO_2 emissions natural gas liquid fractionators are required to report from the complete combustion or oxidation of liquefied petroleum gas supplied in California.

Rationale for Section 95122(a)(1).
This provision is necessary to clearly define the scope of GHGs that natural gas liquid fractionators subject to this part of the regulation are required to report in order to provide sufficient data for the cap-and-trade program consistent with all other industrial sectors.

Summary for Section 95122(a)(2).
This provision adds CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e emissions to the CO_2 emissions local distribution companies are required to report from the complete combustion or oxidation of natural gas supplied in California.

Rationale for Section 95122(a)(2).
This provision is necessary to clearly define the scope of GHGs that local distribution companies subject to this part of the regulation are required to report and to provide sufficient data for the cap-and-trade program consistent with all other industrial sectors.

Summary of Section 95122(a)(3).
This provision specified that consignees for liquefied petroleum gas will report CO_2, CH_4, N_2O, and CO_2e emissions from the complete combustion or oxidation of liquefied petroleum gas supplied in California.

Rationale for Section 95122(a)(1).
This provision is necessary to clearly define the scope of GHGs that consignees for liquefied petroleum gas subject to this part of the regulation are required to report and to provide sufficient data for the cap-and-trade program consistent with all other industrial sectors.

Section 95122(b), Calculating GHG Emissions.

Summary of Section 95122(b)(1).
This provision directs natural gas liquid fractionators to use a Tier 1 (Volume * High Heat Value * Default Emission Factor) or modified Tier 1 (Volume * Default Emission Factor) methodology for calculating emission from liquefied petroleum gas. The emission are summed for the individual components. Emission factors and/or heating

values for any components not listed in 40 CFR 98 Table NN-1 will be taken from Tables MM-1 or C-1

Rationale for Section 95122(b)(1).
This provision is necessary to describe the methods natural gas liquid fractionators will use to estimate CO_2 emissions from the liquefied petroleum gas supplied.

Summary of Section 95122(b)(2).
This provision directs local distribution companies (LDC) to use a Tier 2 (Volume * Annual Average High Heat Value * Default Emission Factor) methodology or modified Tier 2 (Volume * Annual Average Emission Factor) methodology to calculate emission from the pipeline quality natural gas supplied. In either case the reported specific HHV will be used for calculating emissions. For the modified Tier 2 methodology the emission factor will be the product of the reporter specific HHV and the default emission factor from 40 CFR 98 Table NN-1. The LDC will conduct a mass balance around their system with inputs from the city gate, or state boarder, in-state production and storage, and outputs to storage. All other outputs including outputs to other LDCs or customers with greater than or equal to 460,000 Mscf, will be reported and netted out as appropriate by ARB. For natural gas outside the range of 970-1100 the operator will use a Tier 3 (carbon content based) methodology with monthly carbon content testing for estimating emissions. The Tier 3 method will replace the Tier 2 methods as appropriate to estimate emissions.

Rationale for Section 95122(b)(2).
This provision is necessary to describe the methods local distribution companies will use to estimate CO_2 emissions from the natural gas supplied.

Summary of Section 95122(b)(3).
This provision directs natural gas liquid fractionators and LDC to estimate and report CH_4 and N_2O emissions for all fuel supplied according to the methods in 40 CFR 98.33(c)(1)

Rationale for Section 95122(b)(3).
This provision is necessary to describe the methods natural gas liquid fractionators and local distribution companies will use to estimate CH_4 and N_2O emissions from the natural gas supplied.

Summary of Section 95122(b)(4).
This provision directs LCDs to calculate system wide CH_4, N_2O, CO_2 from biomass-derived fuels and CO_2e emissions from the natural gas supplied.

Rationale for Section 95122(b)(4).
This provision is necessary to describe the methods local distribution companies will use to estimate CH_4, N_2O, CO_2 from biomass-derived fuels and CO_2e system wide emissions from the natural gas supplied.

Summary of Section 95122(b)(5).
This provision directs consignees (importers) of liquefied petroleum gas (LPG) to use a modified Tier 1 (Volume * Default Emission Factor) methodology for calculating emission from the liquefied petroleum gas supplied. If compositional analysis of the fuel is available it must be used otherwise the default LPG emission factor from 40 CFR 98 Table C-1 is used. The emission are summed for the individual components, and emission factors for any components not listed in 40 CFR 98 Table NN-1 will be taken from Tables MM-1 or C-1

Rationale for Section 95122(b)(5).
This provision is necessary to describe the methods consignees will use to estimate CO_2 emissions from the liquefied petroleum gas supplied.

Summary of Section 95122(b)(6).
This provision directs consignees of LPG to estimate and report CH_4 and N_2O emissions for all fuel supplied as described in 40 CFR 98.33(c)(1).

Rationale for Section 95122(b)(6).
This provision is necessary to describe the methods consignees will use to estimate CH_4 and N_2O emissions from the liquefied petroleum gas supplied.

Summary of Section 95122(b)(7).
This provision directs all fuel suppliers to calculate the carbon dioxide equivalent emissions of the fuel supplied by summing the products of the metric tons of individual GHG emissions and their respective global warming potentials.

Rationale for Section 95122(b)(7).
This provision is necessary to describe the method for calculating the CO_2e emissions from the CO_2, CH_4 and N_2O emissions for all fuels supplied.
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Summary of Section 95122(c), Monitoring and QA/QC Requirements.
This provision requires suppliers to follow the monitoring and QA/QC requirements of the U.S. EPA Mandatory Reporting Rule. Natural gas suppliers and NGL fractionators are required to measure and record monthly values for volumes, composition, and HHV where required, and LPG consignees are required to record shipment volumes and compositions, if supplied. LPG volumes are corrected to 60 degrees Fahrenheit.

Rationale for Section 95122(c).
This provision is necessary to ensure complete, accurate, and credible GHG emissions data. This requirement for data collection and reporting helps to identify any data errors and greatly assists with the verification of GHG data reports for accuracy and completeness. Frequencies for measurement of fuel analytical data are not always specifically spelled out in the regulation, and from staff's understanding, are often measured at a much higher frequency than monthly; however, staff believes that monthly measurements will provide sufficient accuracy for cap-and-trade.

Section 95122(d), Data Reporting Requirements.

Summary of Section 95122(d)(1).
This provision adds the volume of liquefied petroleum gas supplied in California to the fuels natural gas liquid fractionators are required to report. It also specifies that CO_2, CH_4, N_2O and CO_2e emissions from the complete combustion or oxidation of the volumes supplied must be reported.

Rationale for Section 95122(d)(1).
This provision is necessary to clearly identify the fuels and emissions that natural gas liquid fractionators are required to report.

Summary of Section 95122(d)(2).
This provision requires local distribution companies to provide data additional to the U.S. EPA MRR. Additional reporting requirements include reporting of CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e emissions, and data to aid in verification and netting out of natural gas delivered to covered entities.

Rationale for Section 95122(d)(2).
This provision is necessary to clearly identify the emissions local distribution companies are required to report. This provision also collects additional information to aid in both verification and netting out of natural gas deliveries to capped entities. Natural gas deliveries need to be netted out because the compliance obligation for the fuel will be calculated at the facility.

Summary for section 95122(d)(3).
This provision requires interstate pipelines to report customers information on all their in-state customers.

Rationale for Section 95122(d)(4).
This provision is necessary because the cap-and-trade regulation does not include interstate pipelines as a covered entity, and ARB needs to understand the volume of fuel that may go uncapped.

Summary for Section 95122(d)(4).
This provision requires intrastate pipelines to report as a local distribution company. Intrastate pipelines, instead of using the city gate, will report receipts from interconnects with LDCs, interstate pipelines or other intrastate pipelines as the city gate.

Rational for Section 95122(d)(4).
This provision is necessary because intrastate pipelines are not included in the U.S. EPA MRR. Since reporting requirements are not specified by the U.S. EPA, intrastate pipelines are instructed to use the same reporting methodologies as local distribution companies, with the exception of the city gate as described above. Including them is consistent with the desire of ARB to require reporting for the vast majority of natural gas deliveries in California.

Summary for Section 95122(d)(5).
This provision requires consignees of liquefied petroleum gas to report the volume of LPG, volume of components, if known, and CO_2, CH_4, N_2O and CO_2e emissions for liquefied petroleum gas supplied in California.

Rationale for section 95122(d)(5).
This provision in necessary because the U.S. EPA MRR does not include reporting requirements for entities that import liquefied petroleum gas into California from other domestic sources. This provision specifies what must be reported as well as the methodologies used to report emissions.

Summary of Section 95122(e), Procedures for Missing Data.
This provision applies missing data procedures to ensure data quality is sufficient for a GHG inventory and the cap-and-trade program. It specifies that suppliers must follow the missing data procedures of the U.S. EPA Mandatory Reporting Rule

Rationale for Section 95122(e).
The goal of the reporting program is to collect accurate GHG emissions data. In situations where reporters are not able to collect required data, reporters are required to use standard billing practices to replace missing data. These methods will provide the most accurate data possible in this situation.

Summary of Section 95123, Suppliers of Carbon Dioxide.

This section specifies the GHG reporting requirements and methodologies for suppliers of carbon dioxide.

Rationale for Section 95123.
This section is necessary because, while CO_2 capture and sequestration now occur on a small scale, data concerning the transfer of CO_2 are required to evaluate methods which may remove, rather than emit, CO_2 produced and recovered in industries from combustion and process sources.

Summary of Section 95123(a).
This provision defines which California based facilities must report as suppliers of carbon dioxide:

1. all producers of CO_2;
2. importers of CO_2 with annual bulk imports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons of CO_2e or more; and
3. exporters of CO_2 with annual bulk exports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons of CO_2e or more.

Rationale for Section 95123(a).
This provision is necessary to identify which suppliers of CO_2 are required to report under the regulation.

Summary of Section 95123(b).
This provision establishes missing data substitution procedures which must be used to replace missing data.

Rationale for Section 95123(b).
This provision is necessary to provide a strong incentive for reporters to generate as complete a data set as possible, while specifying how to generate substitution data in circumstances where data was unavoidably lost.

Summary of Section 95123(b)(1).
This provision establishes missing data requirements for stationary combustion emissions.

Rationale for Section 95123(b)(1).
This provision is to ensure that all reporters use the same methodology to report missing data. Consistent missing data requirements for all stationary combustion are necessary to ensure industry wide data consistency.

Summary of Section 95123(b)(2).
This provision establishes missing data requirements for all other GHG data which CO_2 suppliers are required to report.

Rationale for Section 95123(b)(2).
This provision is necessary to ensure data consistency across all California CO_2 suppliers.

Subarticle 3
Additional Requirements for Reported Data

Repeal of Previous Section 95125.

Section 95125 of the current regulation provides various GHG emission estimation methods and calculations required for reporting. The proposed regulation would repeal section 95125.

Rationale for Repeal of Section 95125.
Section 95125 is no longer necessary because emission estimation and other requirements are now included in sector-specific reporting requirements, the revised section 95115 for stationary fuel combustion sources, and other sections of the proposed regulation.

Summary of Section 95129, Substitution for Missing Data Used to Calculate Emissions from Stationary Combustion and CEMS Sources.

This section prescribes methods and procedures for estimating emissions if the data required for calculating emissions are missing.

Rationale for Section 95129.
These provisions are necessary for creating incentives for operators to achieve high data capture rates, and at the same time, preventing gaming of the cap-and-trade system. In assessing the suitability of the U.S. EPA reporting rule for cap-and-trade, it became apparent that many of the U.S. EPA provisions for missing data substitution could potentially be subject to abuse and are not sufficient for cap-and-trade purposes. See Section II.C of this document for a more detailed discussion of the weaknesses of U.S. EPA provisions.

Emissions are either measured directly by CEMS or calculated from measured fuel data. In practice, because measurement equipment and fuel sampling systems may occasionally malfunction, additional requirements to address missing data are necessary to ensure the parameters used to estimate emissions are fully accounted. If some of these required data are missing, emissions can be underestimated, resulting in the reporting entity being responsible for a smaller compliance obligation and creating a perverse incentive to miss more data. This can open up opportunities for gaming the cap-and-trade system. For these reasons, a regulatory prescription for how to substitute for missing data is imperative to ensure the integrity of the carbon market.

Summary of Section 95129(a), Missing Data Substitution Procedures for Units Reporting Under 40 CFR Part 75.
This provision directs operators of 40 CFR Part 75 units to follow the missing data substitution procedures in 40 CFR Part 75, which is consistent with the U.S. EPA rule.

Rationale of Section 95129(a).
This provision is necessary for maintaining consistency with the U.S. EPA GHG reporting rule.

Summary of Section 95129(b), Missing Data Substitution Procedures for Other Units Equipped with CEMS.
This provision directs operators of non-Part 75 units that use CEMS for reporting CO_2 emissions to follow the missing data substitution procedures in 40 CFR Part 75.

Rationale of Section 95129(b).
This provision is necessary for leveling the playing field among the units that use CEMS for reporting GHG emissions. U.S. EPA requires conservative and stringent data substitution only for 40 CFR Part 75 units, but not for other types of units that also use CEMS equipment. Requiring Part 60 CEMS units with CO_2 monitor to follow the 40 CFR Part 75 requirements for CO_2 monitor in operating CEMS units ensures equity in data substitution.

Summary of Section 95129(c), Missing Data Substitution Procedures for Fuel Characteristic Data.
This provision provides instruction for estimating fuel characteristic data, and at the same time, creates an incentive for operators to avoid missing fuel characteristic data.

The operator is required to obtain a valid backup or replacement sample that would still meet the sampling requirements in the applicable California and U.S. EPA rules. If no backup or replacement sample can be obtained but the data capture rate is high, at greater than 90%, the operator is allowed to use the more lenient approach in U.S. EPA's GHG reporting rule. Otherwise, the operator must apply a gradually more stringent missing data estimation procedure depending on the amount of data missed.

Rationale of Section 95129(c).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel characteristic data.

Summary of Section 95129(c)(1).
This provision provides instruction for missing data substitution if data capture rate is higher than 90%.

Rationale of Section 95129(c)(1).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel characteristic data. Fuel characteristic data (such as high heat value and carbon content) generally have a range of values that is not arbitrary by definition, and the variations in values tend to be reasonably bounded. Therefore, staff determined that if a facility is missing a small amount of data (<10%), substituting with the average of the "before" and "after" values consistent with the U.S. EPA rule provides a reasonable estimate.

Summary of Section 95129(c)(2).
This provision gives instruction for missing data substitution if data capture rate is between 80% and 90%. If triggered due to percent data capture rate falling between 80% and 90%, the operator is required to substitute the missing value with the highest value recorded in 3 years.

Rationale of Section 95129(c)(2).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel characteristic data. This provision produces higher emissions numbers for compliance obligation determination; therefore, it creates an incentive for operators to achieve a high data capture rate especially when a carbon price is in place.

Summary of Section 95129(c)(3).
This provision provides instruction for missing data substitution if data capture rate falls below 90%. If triggered due to percent data capture rate falling below 80%, the operator is required to substitute the missing value with the highest value in all records kept. To ensure that the substituted value is at least as conservative as the default heat contents of 40 CFR Part 98 and the default carbon contents of Part 75, the operators are required to use the “greater” of the default value or the highest value in facility records for substitution.

Rationale of Section 95129(c)(3).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel characteristic data. This provision produces noticeably higher emissions numbers for compliance obligation determination; therefore, it creates incentives for operators to achieve a high data capture rate especially when a carbon price is in place.

Summary of Section 95129(d), Missing Data Substitution Procedures for Fuel Consumption Data.
This provision provides instruction for estimating fuel consumption data, and at the same time, creates incentives for operators to avoid missing fuel consumption data. The provision includes missing data substitution procedures for load-based units, non-load-based units, and an alternative substitution method.

Rationale of Section 95129(d).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel consumption data. Unlike fuel characteristic data, which generally has a range of values by definition, fuel consumption can range anywhere from zero to the maximum potential capacity of the equipment. Therefore, staff believes that missing fuel consumption data must be filled with values that can either be correlated with other measured operational parameters or be based on the actual fuel use values under usual operating conditions.

Because compliance obligations are assessed at the facility level, unit-level fuel consumption data do not need to be accurate to +/- 5%. As long as the facility-level fuel consumption data are accurate to +/-5%, best available estimate (consistent with U.S. EPA’s GHG reporting rule) for unit-level fuel consumption data is sufficient. However, if an operator cannot accurately determine facility-level fuel consumption, the operator must use the more stringent missing data procedures prescribed in the following subparagraphs. The stringent procedures produce noticeably higher emissions numbers for compliance obligation determination; therefore, it creates incentives for operators to achieve high data capture rate especially when a carbon price is in place.

Summary of Section 95129(d)(1), Continuous Fuel Flow Rate Data Using Load Ranges.
This provision provides instruction for substituting missing fuel consumption data if load ranges can be established for the unit. The missing data procedure for load-based units

(units producing electrical and/or thermal output that are equipped with a data handling system that can automatically match up output data with fuel use data) is consistent with the methods in 40 CFR Part 75. The operators must substitute missing fuel consumption data based on the unit's actual load range of electricity production or thermal energy production during the hours when the fuel consumption data are missing. This section provides instruction for data substitution when only one fuel is fired as well as when multiple fuels are fired.

Rationale of Section 95129(d)(1).
This provision is necessary to create incentives for operators of load-based units to achieve high data capture rate and to provide a consistent, enforceable rules for substituting missing fuel consumption data.

Staff based the load-based missing data procedure on 40 CFR Part 75 methods because 40 CFR Part 75 procedures for load-based units are capable of producing reasonably accurate estimates. Two major differences between the rule texts in this subparagraph and those in 40 CFR Part 75 are: (1) This subparagraph clarifies the criteria for using the load-based procedures. (2) If not enough historical data are available for a given load range, the use of increasingly higher load ranges are allowed by this subparagraph. In contrast, 40 CFR Part 75 allows only one higher load range before requiring substitution using the maximum potential fuel consumption rate. The proposed approach should yield more accurate substitute data that correlate with fuel consumption values in comparison to the 40 CFR Part 75 approach.

Summary of Section 95129(d)(2), Fuel Consumption Data Without Load Ranges.
This provision gives instruction for substituting missing fuel consumption data if load ranges cannot be established for the unit. If fuel consumption data cannot be accurately determined at the facility level, the operator must use a tiered, increasingly more stringent approach for substituting missing fuel use data. The operators are required to use a best available estimate consistent with the 40 CFR Part 98 if the data capture rate is greater than 95%, use the 90th percentile value of fuel use rates in the facility's records if the data capture rate is between 95% and 90%, use the 95th percentile value of fuel use rates in the facility's records if the data capture rate is below 90% but greater than 80%, and use the maximum potential fuel consumption rate if the data capture rate is below 80%. This section provides instruction for data substitution when only one fuel is fired as well as when multiple fuels are fired.

Rationale of Section 95129(d)(2).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel consumption data. The rule for data substitution produces higher emissions numbers for compliance obligation determination; therefore, it encourages operators to achieve a high data capture rate especially when a carbon price is in place.

In section 95103, the revised rule requires the facility operator to periodically monitor the proper functioning of fuel measurement device and record fuel use data at least weekly. Such monitoring will provide the historical data for missing data substitution. If an individual missing data period is shorter than the fuel consumption data monitoring period, the operator must prorate the measured data to match the missing data period.

Summary of Section 95129(d)(3), Alternate Missing Data Procedure for Fuel Consumption Data.
This provision gives instruction for substituting missing data if a unit does not meet the criteria for using either the load-based or the non-load-based procedure. The operator must conservatively substitute missing data using the maximum potential fuel flow rate.

Rationale of Section 95129(d)(3).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel consumption data. Because fuel consumption can range anywhere from zero to the maximum potential capacity of the equipment, fuel consumption data substitution must be filled with values that can either be correlated with other measured operational parameters or be based on the actual fuel use values under usual operating conditions. In the absence of measured operation parameters or actual fuel use values, the maximum potential fuel consumption rate is the most appropriate alternative. However, given that the proposed rule provides the option for facilities to use a best available estimate if facility level fuel consumption can be accurately determined, staff expects that it will be rare for any facility to use the maximum potential fuel flow rate as the last resort.

Summary of Section 95129(e), Missing Data Substitution Procedures for Steam Production.
This provision gives instruction for substituting missing steam production data. Units that do not use steam production data for emission calculation may follow the more lenient approach in the U.S. EPA rule (best available estimate based on available process data). Units that use steam production data for emission calculation must use a tiered, increasingly more stringent approach for substituting missing steam production data.

Rationale of Section 95129(e).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing steam production data. Because compliance obligation is based on facility emissions, it is necessary to incentivize high data capture rate to prevent gaming. With a carbon price in place, the operators will avoid missing data.

Summary of Section 95129(e)(1).
This provision provides instruction for missing data substitution if the data capture rate is higher than 90%. The operator is allowed to use best available estimate based on available process data that are routinely measured and recorded at the unit.

Rationale of Section 95129(e)(1).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing steam production data. At a high data capture rate, the operator has discretion to use a best available method to estimate missing data, which is consistent with the U.S. EPA approach.

Summary of Section 95129(e)(2).
This provision provides instruction for missing data substitution if the data capture rate is between 80% and 90%. If triggered due to percent data capture rate falling between 80% and 90%, the operators must use the 90^{th} percentile value of fuel use rates in the facility's records.

Rationale of Section 95129(e)(2).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing steam production data. It produces higher emissions numbers for compliance obligation determination; therefore, creating an incentive for operator to achieve a high data capture rate especially when a carbon price is in place.

Summary of Section 95129(e)(3).
This provision provides instruction for missing data substitution if the data capture rate falls below 80%. If triggered, the operators must use the highest valid steam production value recorded in all records kept.

Rationale of Section 95129(e)(3).
This provision is necessary to create incentives for operators to achieve high data capture rate and to provide a consistent, enforceable rule for substituting missing fuel characteristic data. It produces noticeably higher emissions numbers for compliance obligation determination; therefore, creating incentives for operators to achieve a high data capture rate especially when a carbon price is in place.

Summary of Section 95129(f), Procedure for Establishing Load Ranges.
This provision gives instruction for establishing load ranges for a unit that produce electrical or thermal output.

Rationale of Section 95129(f).
This provision is necessary because it enables the implementation of missing data substitution for load based units according to section 95129(d)(1). The procedure is consistent with the 40 CFR Part 75 method.

Summary of Section 95129(g), Executive Officer Approved Load Ranges.
This provision gives operators the option to use other types of load ranges beside electrical or thermal output, and establishes the procedure through which the operator may petition the Executive Officer for approval.

Rationale of Section 95129(g).
This provision is necessary to provide operators some flexibility in estimating missing data with relatively high accuracy. Alternative load metrics are allowed by 40 CFR Part 75. Therefore, the option for alternative load metrics is consistent with the U.S. EPA approach.

Summary of Section 95129(h), Procedure for Approval of Interim Fuel Analytical Data Collection Procedure During Equipment Breakdowns.
This provision lists the criteria and requirements for operators to request ARB's approval of interim data collection procedures during unforeseeable equipment breakdowns.

Rationale of Section 95129(h).
This provision is necessary to give operators some flexibility in complying with the regulation requirements and achieving conformance under unforeseeable breakdowns of equipment. At the same time, it allows for the collection of more accurate data for emissions calculations than if the missing data procedures in sections 95102(b)-(e) are implemented.

In the interest of balancing the collection of accurate data and creating an incentive to achieve a high data capture rate using a conservative substitution approach, the proposed regulation includes provisions to allow operators to submit alternative monitoring plans for ARB's approval in the event of an unforeseeable breakdown of equipment that is expected to cause a missing data rate of more than 20%, which is the threshold for an automatic nonconformance.

Summary of Section 95129(i), Procedure for Approval of Interim Data Collection Procedure During Breakdown for Units Equipped with CEMS.
This provision lists the criteria and requirements for operators that report emissions using CEMS to temporarily use fuel-based methods in the event of an unforeseeable breakdown of CEMS equipment, subject to ARB's approval.

Rationale of Section 95129(i).
This provision is necessary to give operators some flexibility in complying with the regulation requirements and achieving conformance under unforeseeable breakdowns of equipment. At the same time, it allows for the collection of accurate data for emissions accounting than if the missing data procedures in sections 95102(b)-(e) are implemented.

In the interest of balancing the collection of accurate data and creating an incentive to achieve a high data capture rate using a conservative substitution approach, the proposed regulation provides guidelines for an alternative monitoring plan and also makes allowance for sources reporting using CEMS (Tier 4) to temporarily use fuel-based calculation methods (Tiers 2 or 3) if certain criteria are met. This option is only available in the event of an unforeseeable equipment breakdown that is expected to cause missing data rate of more than 20%, which is the threshold for an automatic nonconformance.

Summary of Section 95129(j), Cumulative Missing Data Elements.
This provision defines the minimum amount of data that must be captured in order to avoid a nonconformance finding. A nonconformance may not prevent a positive verification finding, depending on the contribution of the source to the facility emissions total.

Rationale of Section 95129(j).
This provision is necessary to maintain a certain level of data quality in conformance determinations during verification. Missing data elements cumulatively causing more than 80% of emissions to not be directly calculated from measure parameters is an automatic nonconformance even if the operator has correctly followed all the missing data substitution procedures in the regulation.

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

This subarticle includes additions and modifications to the existing verification requirements of the current ARB GHG reporting regulation. These additions and modifications are summarized below, and an explanation of their necessity is also included. Provisions which have been retained and are not modified are not described below.

Summary of Section 95130, Requirements for Verification of Emissions Data Reports.

This section continues to specify that all emissions data reports are subject to annual verification and full verification with a site visit under certain circumstances. It also includes revisions to the verification requirements of the existing ARB GHG reporting regulation.

Rationale for Section 95130.
This section is necessary to inform reporting entities that they must obtain verification of their emission data reports on an annual basis. Verification is necessary to ensure the reported emissions do not contain a material misstatement and are reported in conformance with the requirements of the regulation. The changes to the existing requirements are necessary to provide a more rigorous verification schedule and process to support a cap-and-trade program.

Summary of Section 95130(a)(1), Annual Verification.
This provision clarifies that emissions data reports are subject to an annual verification. Triennial verification was removed as an option for verifiers and criteria were added to ensure a full verification takes place for 2011 data, when there is a change in a

verification body, when ownership of the reporting entity changes, when a previous year's emissions data report received an adverse verification statement, or when reported GHGs or MWhs differ greater than 25 percent from the previous year.

Rationale for Section 95130(a)(1).
This provision is necessary because annual verification ensures the rigorous reporting mechanism needed to support the cap-and-trade program. The new criteria to prompt a full verification are necessary to ensure that there is a complete review at the facility site when large changes occur in emissions or a change in ownership from one year to the next.

Summary of Section 95130(a)(2).
This provision maintains the requirement for reporting entities to switch verification bodies and verifiers at least once every six years.

Rationale for Section 95130(a)(2).
This provision is necessary to ensure that reporting entities and verification bodies do not fall into comfortable and close business relationships which could lead to bias in the verification process.

Summary of Section 95131, Requirements for Verification Services.

This section clarifies and strengthens the existing requirements for verification services. It also provides methods for an Executive Officer to estimate emissions for reporting entities that receive an adverse verification statement (formerly, opinion) and a third option for a verification statement to let reporting entities with a non-conformance still use their reported data as a basis for a compliance obligation if the non-conformance does not lead to a material misstatement.

Rationale for Section 95131.
The changes and additions in this section are needed to provide consistency and clarity in the existing requirements and to support a cap-and-trade program.

Summary of Section 95131(a)(1), Notice of Verification Services.
This provision includes language to clarify that when conflict of interest and notice of verification services (COI/NOVS) forms are submitted together, the verifier must still wait 10 working days after the approval is issued, to begin verification services. ARB must be notified of any changes in the verification team at least 5 days before new staff participate in verification services.

Rationale for Section 95131(a)(1).
This provision is needed to add clarity to an existing requirement that allows verification bodies to streamline the conflict of interest and notice of verification services information to ARB. The clarification states that even with a combined submittal, ARB is still provided a 10 working day window to coordinate an audit with that verifier. A five-day period for ARB review of staff changes is needed to evaluate the potential conflict

between the operator and the new staff of the verification body or subcontractor.

Summary of Section 95131(a)(2).
This provision adds new sector specialists for new complex sources that require an in-depth understanding of industrial processes.

Rationale for Section 95131(a)(2).
This provision is needed because newly added industrial sectors require that verifiers need sector training in order to provide a thorough review of the emissions data reports.

Summary of Section 95131(a)(3).
This provision removes the requirement to provide duplicative information about the lead verifier.

Rationale of Section 95131(a)(3).
This provision was needed to remove duplicative information as part of the Notice of Verification Services submittal as this information has already been submitted as part of the Conflict of Interest form.

Summary of Section 95131(a)(4).
This provision requires that any change to information submitted to ARB under sections 95131(a)(1) and 95131(a)(3) be reported to ARB at least 5 working days prior to the start of verification services, and prior to the verification statement being submitted to ARB.

Rationale of Section 95131(a)(4).
This provision is needed to keep ARB updated with any change of submitted information during the verification process. ARB needs timely information about verifications to be able to plan and participate in verification audits.

Summary of Section 95131(b)(1)-(3), Verification Plan.
These provisions clarify requirements for verification plans, including the information required in the plan and that the verification body must discuss the scope of verification services with the reporting entity.

Rationale for Section 95131(b)(1)-(3).
These provisions are necessary to remove ambiguity and provide a clear standard for all verification plans.

Summary of Section 95131(b)(4).
This provision includes clarifications to existing requirements and a new requirement for sites visits to include a sector specialist, when applicable.

Rationale for Section 95131(b)(4).
This provision is necessary to remove ambiguity in existing requirements and ensure that a sector specialist who is most familiar with the types of sources for a reporting entity is part of the team that conducts a site visit.

Summary of Section 95131(b)(5)-(7).
These provisions include clarifications to existing requirements for activities conducted as part of assessing the completeness of the emissions data report and that reporting entities must provide any information required for verification to the verification team. Additional requirements are described that require verifiers to review specific information during the verification of an entity with electricity transactions.

Rationale for Section 95131(b)(5)-(7).
These provisions are necessary to remove ambiguity in existing requirements and provide clear direction on requirements for verifiers and reporting entities.

Rationale of Section 95131(b)(8), Sampling Plan.
This provision requires more information to be evaluated in the sampling plan for existing emissions data reports, including biofuels, and that it be updated as relevant information is identified during verification.

Summary of Section 95131(b)(8).
This provision is necessary to ensure that each verification body and verifier had a minimum standard of what was expected as part of developing a sampling plan for emissions data reports, including reports that include biofuels.

Summary of Section 95131(b)(9), Data Checks.
This provision adds new specific requirements when performing Data Checks, including tracing original data, reviewing data compliance and completion, recalculating where possible and reviewing meter instrumentation accuracy.

Rationale of Section 95131(b)(9).
This provision is necessary to ensure minimum quality in the data checks and provide consistency between all verifications so that key aspects of the emissions data report are evaluated.

Summary of Section 95131(b)(10) Emissions Data Report Modifications.
This provision requires reporting entities to correct errors in the emissions data report where possible.

Rationale of Section 95131(b)(10).
This provision is needed in order to get the most accurate data possible. Reporters will now be required to fix problems in their emissions data reports, whereas the current regulation does not require mistakes in the report to be fixed by the reporting entity.

Summary of Section 95131(b)(11), Findings.
This provision maintains the requirement for verification teams to recalculate emissions for sources selected for data checks and evaluate the emissions data report for conformance with the regulation.

Rationale of Section 95131(b)(11).
This provision is needed to clarify to verifiers what they need to do as part of determining their findings for an emissions data report.

Summary of Section 95131(b)(12), Log of Issues.
This section requires that the verifier add specific information to the log of issues.

Rationale of Section 95131(b)(12).
This provision is necessary to provide standard information in the issues log for reporting entities. The additional text provides a clear listing of what verifiers must include in the log of issues so that reporting entities know what was wrong in the emissions data report and how the issues were resolved, and supports ARB oversight and audits.

Summary of Section 95131(b)(13)-(14).
These provisions include a materiality misstatement assessment equation and describe how to apply it to the emissions data report.

Rationale for Section 95131(b)(13)-(14).
These provisions are necessary to provide a consistent method for all verifiers to assess the quality of the emissions data report. The equation is already being used in existing voluntary and regulatory programs. Material misstatement is only assessed for emissions that would have an obligation under the cap-and-trade program.

Summary of Section 95131(b)(15), Conformance.
This provision requires a verification team to review specific information in the emissions data report for conformance with the regulation, but does not require all of that information to be subject to a material misstatement assessment.

Rationale for Section 95131(b)(15).
This provision is needed to ensure that all information in the emissions data report chosen for data checks was subject to all of the verification services. However, only the emissions sources chosen as part of the data checks are subject to a material misstatement assessment.

Summary of Section 95131(b)(16), Review of Missing Data Substitution.
This provision adds requirements for how emissions calculated using the missing data provisions will be treated during the material misstatement assessment.

Rationale for Section 95131(b)(16).
This provision is needed to provide direction to the verification team on how to evaluate the accuracy of emissions calculated using the missing data substitution requirements of this regulation.

Summary of Section 95131(c)(1)-(3), Verification Statement.
These provisions change the term verification opinion to verification statement and provide more detail on the duties of the independent reviewer. The verification team is now required to have a final discussion with the reporting entity in order to explain the findings of the verification.

Rationale for Section 95131(c)(1)-(3).
These provisions are needed to make terminology consistent with other comparable programs, and to give more direction to the lead verifiers in a verification body that act in the capacity of an independent reviewer. The requirement for the verification team to discuss the findings with the reporting entity and the requirement to describe the cause of an adverse statement provides more information to the reporting entity regarding any mistakes identified in the emissions data report.

Summary of Section 95131(c)(4).
This provision shortens the deadlines for the Executive Officer to make a determination on the verifiability of the report, and for the reporting entity to have their emissions data report verified, if applicable.

Rationale for Section 95131(c)(4).
This provision is necessary to support the need for timely data in a cap-and-trade program.

Summary of Section 95131(c)(5), Assigned Emissions Level.
This new provision provides criteria for how the Executive Officer will calculate an assigned emissions level to form the basis of a surrender obligation when an emissions data report receives an adverse verification statement.

Rationale for Section 95131(c)(5).
This provision is necessary so that a reporting entity that does not provide accurate data in their emissions data report can be assigned a number that forms the basis of their obligation in the cap-and-trade program. The criteria will support the Executive Officer to assign a representative and conservative emissions number to the reporting entity.

Summary of Section 95131(d).
This provision states that the verification requirements are complete once a verification statement is submitted to ARB and changes are no longer allowed to be made to emissions data reports after the verification statement is submitted to ARB.

Summary for Section 95131(d).
This provision is necessary to provide accurate and stable data for use in the cap-and-trade program.

Summary of Section 95131(e).
This provision states that where a high conflict of interest is discovered between the reporting entity and the verification body, or where a facility with a positive or qualified positive verification statement fails an ARB audit, the Executive officer may set aside the statement and require the facility to be reverified within 90 days.

Rationale for Section 95131(e).
This provision is necessary to deter high conflict of interest relationships between verifiers and reporters, and provides clear requirements for re-verification.

Summary of Section 95131(f).
This provision requires the reporting entity to provide detailed information about the emissions data report to the Executive Officer within 10 working days of a request by ARB.

Rationale for Section 95131(f).
This provision is needed to ensure a timely response by reporters as part of ARB's program oversight.

Summary of Section 95131(g).
This provision requires verification bodies to provide specified information to the Executive Officer within 10 working days of a request by ARB.

Rationale for Section 95131(g).
This provision is needed to ensure ARB is able to provide program oversight and has the ability to audit verifications to ensure conformance with the requirements of the regulation by gaining access to relevant documents from the verification body within a timely manner.

Summary of Section 95131(h), ARB Audits.
This provision states that ARB must provide written notification to verification bodies in order to audit individual verifiers that provide verification services.

Rationale for Section 95131(h).
This provision is needed to ensure ARB is able to audit individual verifiers to ensure verifiers are providing high quality verification services.

Summary of Section 95131(i), Biomass-Derived Fuels.
This provision requires additional verification steps to verify reported emissions that include biomass-derived fuels that are not subject to an obligation in the cap-and-trade program. The requirements include site visits and document reviews for every party in

the chain of custody between the biomass-derived fuel producers to the reporting entity that is including those emissions in their emissions data report.

Rationale for Section 95131(i).
This provision is needed because there is no established system to track biomass-derived fuels once they are injected into a common transmission pipeline. In many cases, a reporter claiming biomass-derived emissions may not actually be combusting the fuel they bought from out of state. Because the emissions from these fuels are exempt from being subject to an obligation, there needs to be a way to ensure the purchases of such fuels did occur from an actual biomass-derived fuel producing facility and that there is no double crediting or selling of these fuels from the point of production to the point of combustion. These requirements are needed to uncover any false claims of emissions from biomass-derived fuels.

Summary of Section 95131(i)(1).
This provision requires conflict of interest to be assessed by the verification body against every entity that sold, produced, or combusted the biomass-derived fuel.

Rationale for Section 95131(i)(1).
This provision is needed to ensure that every entity in the chain of custody of the biomass-derived fuel has no existing financial or other relationship with the verification body that could lead to any type of bias during the verification process.

Summary of Section 95131(i)(2), Biofuel Chain-of-Custody Evaluation.
This provision requires a verifier to make a site visit to each entity in the chain of custody for the fuel during the years full verification in required. The site visit will be to the location of data management when the biomass-derived fuel entity is a marketer, distributor, or suppler who does not produce or store the fuel on site. Verifiers must review fuel contracts and make determinations on whether the contract was in place before January 1, 2010 or the fuel is part of increased production at the facility. The verifier must also determine whether the fuel is already part of offset credits, whether the facility is producing fuel in accordance with 95852.2, whether the reported chain of custody and data monitoring is accurate, and the accuracy of the reported fuel volumes and emissions.

Rationale for Section 95131(i)(2).
This provision is needed to prevent contract shuffling that results in no actual GHG emissions reductions, ensure that biomass-derived fuels are not receiving credit for GHG reductions under any other program, that only increased biomass-derived fuel production avoids compliance obligations unless an existing contract is in place before January 2010, and that the fuel is tracked and managed accurately so that the verifier can establish ownership through the entire supply chain.

Summary of Section 95131(i)(3).
This provision states that if any entity in the chain of custody for biomass-derived fuels does not provide required information to the verifier, the biofuel will be considered unverifiable and subject to a compliance obligation.

Rationale for Section 95131(i)(3).
This provision is needed so that the verifier can review documentation to establish the chain of custody for biomass-derived fuels and to assess the validity of the avoided compliance obligation. This provision specifies the consequences when that data is not made available to the verifier.

Summary of Section 95131(i)(4).
This provision states that verifiers must evaluate material misstatements by comparing errors, omissions and misreporting with the reported emissions. Verifiers review methods and factors to determine conformance with the regulation.

Rationale for Section 95131(i)(4).
This provision is needed to ensure that biomass-derived fuels are evaluated for materiality and conformance using the same methods as verifiers use for emissions from facilities.

Summary of Sections 95131(i)(5).
This provision states that biomass-derived fuels must be measured accurately to within 95%, that heat content must be calculated correctly using a specified method, and that 95% of the data must be collected and provided to the verifier upon request. If these specified criteria are not met, the fuel is considered unverifiable and the operator is subject to a compliance obligation for the unverified biofuel.

Rationale for Section 95131(i)(5).
This provision is needed so that fuel providers understand that in order for fuel to be verified as biomass-derived, the fuel must be measured accurately, the heat content must be calculated using the method in 95115(c), and that if any of the biofuel providers or suppliers in the chain of custody do not collect at least 95% of the data used to evaluate the fuel, all of the fuel is considered unverifiable, which includes fuel where data was collected correctly, and not just the portion of fuel where data was missing for that reporting year.

Summary of Section 95131(i)(6).
This provision states that any operator that has reported a fuel which cannot be successfully verified as a biomass-derived fuel without a compliance obligation, will have an obligation for that fuel.

Rationale for Section 95131(i)(6).
This provision is needed to ensure that any claim of emissions that are attributed to a biomass-derived fuel that are included in an emissions data report that receives an

adverse verification statement will be subject to a compliance obligation in the cap-and-trade program.

Summary of Section 95132(a), Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers of Emissions Data Reports and Offset Project Data Reports.

This section requires verification bodies, lead verifiers, and verifiers for both mandatory reporting and offset project verification to meet the accreditation requirements of this section.

Rationale for Section 95132(a).
These changes were necessary in order to establish consistent accreditation requirements for verification services for this article and the cap-and-trade regulation.

Summary of Section 95132(b)(1)-(3).
These provisions require an increase in liability insurance to four million dollars and a requirement to maintain that insurance for three years after completing verification services. Staff training now includes participating in ARB verifier training on an ongoing basis. Along with current requirements for sector specific verifiers, language was added to require offset project specific verifiers to seek sector accreditation. Existing verifiers will also have to take ARB approved training on the revisions to the regulation to continue to provide verification services. Language grandfathering verifiers from other programs into ARB's program has been removed.

Rationale for Section 95132(b)(1)-(3).
These provisions are necessary because the cap-and-trade program will monetize emissions, and so it is especially important for verification bodies to carry enough liability insurance for a sufficient period of time after verification in order to provide recourse to a client for any errors in their work. This new level of insurance is comparable to the level of insurance required for verification bodies in voluntary programs. The insurance has to be maintained long enough to cover one compliance period amount under the reporting program. Accredited verifiers must keep current with regulatory changes and updates, so continued training is needed to ensure a rigorous verification program.

Summary for Section 95132(b)(4).
This provision adds language requiring certain standards for all ARB-approved training. These standards include receiving a 70% passing score on the final examination, and one opportunity for a retake of the exam. The provision does not allow for exams to be retaken under previous versions of the regulation after training has been updated for the new version of the regulation.

Rationale for Section 95132(b)(4).
This provision is necessary to create consistency amongst verification training and verifiers.

Summary of Section 95132(b)(5)-(6), Sector Specific and Offset Project Specific Verifiers.
These provisions add minimum requirements for Sector Specific and Offset Project Specific Verifiers to require at least two years of professional experience in the sector in which they wish to obtain accreditation. Other requirements include being in good standing with CAR prior to November 1, 2010 and having performed at least two project verifications by December 31, 2010, or having two years of professional experience related to the offset type as well as taking ARB project specific verification training, and passing the course and the final course exam. These provisions also clarify that the Executive Officer may request additional information about the qualifications of the accredited verifier or verification body.

Rationale for Section 95132(b)(5)-(6).
These provisions are necessary to ensure sector and offset verifiers have the skills and knowledge to understand and verify sources in their sectors. These provisions are also needed because the Executive Officer must be able to obtain sufficient information about all accreditation applicants, including information not specified in the regulation, in order to evaluate their accreditation fairy and accurately.

Summary of Section 95132(c)(1)-(4), Re-Accreditation by ARB.
These provisions include new language related to re-accreditation for a verification body, verifier or lead verifier. Any verification body or verifier that is subject to ARB enforcement action will not be re-accredited. All training requirements must be fulfilled at the time of reapplication with requirements added to ensure that applicants who did not participate in one verification by January 1, 2012 must take part in ARB approved GHG verification training, receiving at least a 70% passing score on the exit examination. Similarly, applicants who have participated in a verification before January 1, 2012 must take ARB approved abbreviated GHG training that includes training on changes to the regulation. Verifiers seeking reaccreditation must also score at least 70% on the exit exam during training.

Rationale for Section 95132(c)(1)-(4).
These provisions are needed to ensure that re-accreditation is only allowed for qualified verifiers and ensures that all verifiers fully understand any new components of the program. The requirements are necessary to provide consistency amongst the verifiers and in the verification program.

Summary of Section 95132(c)(5)-(8).
These provisions require verification bodies to meet the requirements of the regulation in order to be re-accredited by the Executive Officer. Verifiers may be re-accredited for a longer time than 3 years if specified criteria are met. If corrective action is required under a different program, the verifier must notify ARB and provide information about that action. Additional training is required for verifiers that are accredited before January 2011.

Rationale for Section 95132(c)(5)-(8).
These provisions are needed to ensure verification bodies are in good standing with ARB and other GHG programs before re-accreditation is renewed. It is necessary for ARB to evaluate any corrective actions in other programs in order to ensure any verifier weaknesses are identified, and that verifiers take more training so that they have a complete understanding of changes to the regulation.

Summary of Section 95132(d), Revocation of Accreditation by ARB.
This provision allows the Executive Officer to review and revoke an accreditation for any violation of subarticle 4, or an analogous GHG system. Limits are placed on verification body and verifiers so that they may not continue to offer verification services during the suspension or revocation process. If a verification body or verifier has their accreditation suspended or revoked, they must notify their current clients or clients for whom they have provided services in the past 6 months, within 5 working days and the clients must contract for verification services with a different verification body.

Rationale for Section 95132(d).
This provision is necessary because it is important to the quality of the program to not allow verifiers or verification bodies to continue to be active when serious concerns over their work have been uncovered in other voluntary or mandatory programs. The new requirements allow the Executive Officer to act on any concerns regarding a verifier or verification body's conduct in any similar voluntary or mandatory program to maintain quality in the ARB program. Reporting entities, offset project operators, and authorized project designees will now be informed in a timely manner if they need to contract with a new verifier or verification body.

Summary of Section 95132(e).
This provision specifies how subcontractors may participate on a verification team, and requires a lead verifier that is not a subcontractor to be the independent reviewer for the verification body.

Rationale for Section 95132(e).
This provision is necessary to clarify that only employees of the verification body may review the work done on behalf of the verification body. This requirement ensures that only full-time employees of a verification body are assigned the responsibility of evaluating the regulatory and financial liabilities of providing verification services under ARB's GHG program, and of protecting the business interests of that verification body.

Summary of Section 95133, Conflict of Interest Requirements for Verification Bodies for Emissions Data Reports.

Summary of Section 95133(a).
This section includes changes to clarify and strengthen the conflict of interest requirements between verification bodies, verifiers, and reporting entities.

Rationale for Section 95133(a).
This section is necessary to ensure a truly unbiased review of emissions data reports. The integrity of the verification program relies heavily on the true independence of verifiers as they review an emissions data report for a reporting entity.

Summary of Section 95133(b), High-risk Conflict of Interest.
This provision requires additional activities to be included as a high-conflict activities. Also added were owning, buying, and trading shares in an offset project, dealing with credits on behalf of an offset project manager, or where any staff member of the verification body provides any type of incentive to an operator to secure a contract. Definitions for “member” and “related entity” for the purposes of this section have been added.

Rationale for Section 95133(b).
This provision is necessary to ensure that there is no bias in the independent review of the submitted GHG emissions data report, especially if those sources or systems are subject to review for other purposes. The new activities acknowledge the increased activity in offsets and their close relationship to GHG accounting and that these activities are within the realm of GHG services that could be provided to the same reporters subject to the market program. The limits on incentives to procure verification services ensure that the program maintains a high level of objectivity. The new definitions provide for a consistent interpretation of those terms by verification bodies as they assess their conflict of interest.

Summary of Section 95133(c), Low-risk Conflict of Interest.
This provision requires the verification body to evaluate any non-verification work performed for the operator within the past 3 years in order for the conflict of interest for a verification to be identified as a low conflict under certain criteria.

Rationale for Section 95133(c).
This provision is needed to ensure that previous non-verification work represents a small fraction of the work done for that reporting entity, and that the non-verification work does not bias the verification work performed by the verification team.

Summary of Section 95133(d), Medium-risk Conflict of Interest.
This provision specifies how a verification body determines if a conflict of interest is a medium risk. A medium risk includes any risk that is not low or high risk. A medium risk is also identified when any personal or family relationships exist between the operator and the staff of the verification body. The verification body is required to disclose the nature of the conflict in a mitigation plan, and the Executive Officer evaluates the conflict and determines if the verification may proceed.

Rationale for Section 95133(d).
This provision is necessary to ensure that existing relationships are disclosed to ARB so the Executive Officer may review and determine if the relationship may impact the impartiality of the verification body. A medium conflict requires the verification body to

submit a mitigation plan to ARB so that a written accounting of the conflict can be reviewed.

Summary of Section 95133(e).
This provision requires verification bodies to self-evaluate their risk of conflict of interest for verifications, identify the nature of any past work, and to attest that their assessment is true, accurate, and complete.

Rationale for Section 95133(e).
This provision is necessary to ensure that verification bodies carefully evaluate their potential conflict of interest, disclose any previous business relationships with reporting entities, and attest to the accuracy of the conflict of interest submittal.

Summary of Section 95133(f), Conflict of Interest Determinations.
This provision reduces the time allowed for providing a conflict of interest determination by the Executive Officer.

Rationale for Section 95133(f).
This provision is needed to ensure a timely response to support a shorter verification period, and to identify what actions the Executive Officer may take if an emerging conflict of interest is identified during or after verification has occurred, including revocation of accreditation.

Summary of Section 95133(g), Monitoring of Conflict of Interest Situations.
This provision requires the verification body to inform the Executive Office if they have an emerging conflict of interest. The provision also requires the verifier to submit a mitigation plan for review if the new situation is considered "medium" conflict. If the new situation is a high conflict, services may not proceed, and accreditation for the verification body may be revoked.

Rationale for Section 95133(g).
This provision is needed to clarify what "emerging conflict" means and implications for the concurrent verification services, and allows the verification body and reporting entity to assess the risk to the verification process and verification body or verifier accreditation as they consider any new contracts for additional work.

Subarticle 5
Reporting Requirements and Calculation Methods for Petroleum and Natural Gas Systems

Subarticle 5 sets forth reporting requirements in the following sections:

95150: Definition of the Source Category
95151: Reporting Threshold
95152: GHGs to Report
95153: Calculating GHG Emissions

95154: Monitoring and QA/QC Requirements
95155: Procedures for Estimating Missing Data
95156: Data Reporting Requirements
95157: Records that Must be Retained
95185: Data Tables

Rationale for Subarticle 5.
This provision is necessary because at the time the current ARB GHG reporting regulation was designed it was recognized that both combustion and process/vented emissions were important GHG emissions sources for this sector. Initially oil and gas producers only reported stationary combustion emissions. ARB staff has worked with WCI partners to develop methods for the reporting of additional process/vented emission sources. The Draft U.S. EPA Mandatory Reporting Rule did contain methods specific to this sector in Subpart W – Oil and Natural Gas Systems. This section was withdrawn before the U.S. EPA MRR became final on October 30, 2009. Subpart W was subsequently re-released by U.S. EPA and is currently in draft form. Since its re-release, ARB staff has been working with the WCI Reporting Committee's Oil and Gas Subcommittee' to harmonize the WCI Draft methods with this U.S. EPA draft. Subarticle 5 is the result of this harmonization process. Most of the U.S. EPA proposed methodologies were adopted with no or very minor changes. For several sources, WCI determined that major modifications were required. The changes set forth in this Subarticle were deemed necessary to ensure that all methods produced data that was cap-and-trade quality. In several instances, WCI concluded that there were not methodologies available which would produce cap-and-trade quality data and these methods are included in this Subarticle for reporting purposes only.

Summary of 95150, Definition of the Source Category.

This provision defines the Source Category for the Petroleum and Natural Gas Systems as follows:

1. offshore petroleum and natural gas production
2. onshore petroleum and natural gas production
3. onshore natural gas processing plants
4. onshore natural gas transmission compression
5. underground natural gas storage
6. liquefied natural gas (LNG) storage
7. LNG import and export equipment
8. natural gas distribution

Rationale for Section 95150.
This provision is necessary to define which sectors must report and the reporting footprint for each of the eight sectors which are required to report under this regulation.

Summary of Section 95151, Reporting threshold.

This section points operators to the appropriate section where the reporting threshold is defined. It also directs operators to report emissions from portable equipment which may be stationed at a wellhead during the producing lifetime of the well.

Rationale for Section 95151.
This section is necessary to define the reporting threshold for this sector and clarify reporting responsibilities for stationary combustion emissions for portable equipment – emissions that may take place as the result of contracted services.

Summary of Section 95151(a).
This provision directs reporters to section 95150 and 95101(e) where the facility definition and reporting threshold for this sector are defined. It also clarifies that a reporting entity with more than one permit to operate wells in a basin would be considered one facility for purposes of reporting.

Rationale for Section 95151(a).
This provision is necessary to define who is required to report.

Summary of Section 95151(b).
This provision requires that the operator must include combustion emissions from portable equipment in its emissions data report.

Rationale for Section 95151(b).
This provision is necessary to ensure that all significant emissions from all aspects of crude oil and natural gas production are reported.

Summary of Section 95152, GHGs to Report.

This provision defines which sources must be reported for each of the eight sectors which are required to report in Section 95150.

Rationale for Section 95152.
This provision is necessary to define the reporting footprint for each of the eight sectors which are required to report.

Summary of Section 95152(a).
This provision establishes reporting requirements for industry segments in paragraph (b) through (i) of this section. It also requires reporting of flare emissions (section k) and requires operators to use provisions in section 95123 to report mass of all captured and supplied CO_2.

Rationale for Section 95152(a).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified.

Summary of Section 95152(b).
This provision establishes reporting requirements for offshore petroleum and natural gas production, including all stationary fugitive and stationary vented sources as defined in the Mineral Management Service Gulfwide Offshore Activity Data System study (2005 Gulfwide Emission Inventory Study MMS 2007-067).

Rationale for Section 95152(b).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of offshore petroleum and natural gas production facilities what they must report.

Summary of Section 95152(c).
This provision establishes reporting requirements for onshore natural gas processing.

Rationale for Section 95152(c).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of onshore natural gas processing facilities what they must report.

Summary of Section 95152(d).
This provision establishes reporting requirements for onshore petroleum and natural gas production.

Rationale for Section 95152(d).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of offshore petroleum and natural gas production facilities what they must report.

Summary of Section 95152(e).
This provision establishes reporting requirements for onshore natural gas transmission compression.

Rationale for Section 95152(e).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of onshore natural gas transmission compression facilities what they must report.

Summary of Section 95152(f).
This provision establishes reporting requirements for underground natural gas storage.

Rationale for Section 95152(f).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of underground natural gas storage facilities what they must report.

Summary of Section 95152(g).
This provision establishes reporting requirements for LNG storage.

Rationale for Section 95152(g).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of LNG storage facilities what they must report.

Summary of Section 95152(h).
This provision establishes reporting requirements for LNG import and export equipment.

Rationale for Section 95152(h).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of LNG import and export equipment what they must report.

Summary of Section 95152(i).
This provision establishes reporting requirements for natural gas distribution.

Rationale for Section 95152(i).
This provision is necessary because each of the industry segments have different reporting requirements which must be individually specified, and to inform operators of natural gas distribution facilities what they must report.

Summary of Section 95152(j).
This provision requires operators to report all flaring emissions.

Rationale for Section 95152(j).
This provision is necessary because flaring emissions from the industry segments can represent a large emission source and as such must be reported.

Summary of Section 95152(k).
This provision directs reporters to section 95115 where methodologies for the calculation of stationary combustion emissions are set forth.

Rationale for Section 95152(k).
This provision is necessary because standard methods are required across all entities to ensure data consistency and accuracy.

Summary of Section 95152(l).
This provision directs reporters to section 95123 where rules for reporting supplied CO_2 are established.

Rationale for Section 95152(l).
This provision is necessary to ensure complete GHG reporting for the petroleum and natural gas industry, and clarifies that operators must report all quantities of CO_2 captured and transferred.

Summary of Section 95153, Calculating GHG Emissions.

This provision contains all the reporting methodologies as well as methods for calculating volumetric and mass GHG emissions. This section also requires operators to report stationary combustion emissions and report all CO_2 sold and transferred off-site using methods in Section 95123.

Rationale for Section 95153.
This provision is necessary to define the methods that operators must use.

Summary of Section 95153(a), Natural Gas Pneumatic High Bleed Devices and Pneumatic Pump Venting.
This provision defines reporting methods for all high bleed natural gas powered pneumatic devices and pneumatic pumps. This section provides a graduated reporting requirement where reporters are required to meter 50 percent of all high bleed and pneumatic pump device natural gas emissions in year one (2013) and meter 100 percent of these emissions in year 2 (2014). Use of common plumbing and metering is encouraged wherever possible. Operators may use OEM derived emissions data for all low bleed pneumatics and un-metered devices and pumps.

Rationale for Section 95153(a).
This provision is necessary because WCI and ARB have required changes to the draft U.S. EPA language for this source to ensure that cap-and-trade quality data are generated. A graduated approach over two years has been proposed to give operators time to install the required metering.

Summary of Section 95153(a)(1).
This provision provides operators with a time line for the metering of all high bleed pneumatic devices and pneumatic pumps.

Rationale for Section 95153(a)(1).
This provision is necessary because metering of natural gas for high bleed pneumatics and pneumatic pumps is required and operators must install meters in an established time frame to meet the reporting requirements.

Summary of Section 95153(a)(2).
This provision details the methodology for the calculation of CH_4 and CO_2 from unmetered high bleed pneumatic devices and pneumatic pumps.

Rationale for Section 95153(a)(2).
This provision is necessary because only a portion of high bleed pneumatic devices and pumps must be metered during the first reporting year and this section sets forth reporting requirements for unmetered devices and pumps.

Summary of Section 95153(a)(3).
This provision details the methodology for the calculation of CH_4 and CO_2 from metered high bleed pneumatic devices and pneumatic pumps.

Rationale for Section 95153(a)(3).
This provision is necessary because only a portion of high bleed pneumatic devices and pumps must be metered during the first reporting year and this section sets forth reporting requirements for metered devices and pumps.

Summary for Section 95153(a)(4).
This provision directs reporters to methods for converting natural gas volumes to GHG mass emissions.

Rationale for Section 95153(a)(4).
This provision is necessary because natural gas consumption data derived from meters must be converted and reported as GHG emissions.

Summary for Section 95153(b), Natural Gas Pneumatic Low Bleed Device Venting.
This provision has been adopted without change from the U.S. EPA draft MRR. Operators may use OEM supplied data for all low bleed devices. Metering is not required for this group of devices given their low emissions rates compared with the high and continuous bleed devices and pneumatic pumps.

Rationale for Section 95153(b).
This provision is necessary because low bleed devices are defined as controllers where the bleed rate is equal to or less than six standard cubic feet per minute. These devices contribute a small fraction of the total emissions from pneumatic devices, thus a more relaxed methodology is appropriate.

Summary of Section 95153(b)(1).
This provision directs reporters to methods for the conversion of natural gas volumes to GHG mass emissions.

Rationale for Section 95153(b)(1).
This provision is necessary because meter derived natural gas consumption volumes must be converted to report CO_2 and CH_4 mass emissions.

Summary for Section 95153(c), Acid Gas Removal (AGR) Vent Stacks.
This provision establishes reporting requirements for Acid Gas Removal Vent Stacks. Operators must measure the volume weighted CO_2 content of gas entering and exiting the AGR unit on a quarterly basis. Two methods are provided. For absorbent based

dehydrators operators must use the GRI-GLYCalc simulation software. Operators using desiccant based dehydrators must use a method where desiccant volume and pressure are sued to calculate emissions which occur when the vessel is vented for desiccant refilling.

Rationale for Section 95153(c).
This provision is necessary because the U.S. EPA draft rule requires the use of a mass balance approach when determining CO_2 emissions from AGR vent stacks. ARB is recommending inclusion of this method without modification because AGR units are recognized to be a significant source of CO_2 and thus should be reported as part of a comprehensive GHG strategy. The proposed method uses data which operators already determine for operational control and gas QA/QC purposes and thus should not require additional sampling efforts.

Summary for Section 95153(d), Dehydrator Vent Stacks.
This provision sets forth methods for the calculation of vented emissions from absorbent and desiccant natural gas dehydrators which represent a significant source of natural gas methane and carbon dioxide emissions.

Rationale for Section 95153(d).
This provision is necessary because methane and CO_2 emissions resulting from the dehydration of natural represent a significant GHG source. Calculation methodologies must be applicable for both liquid absorbent technology and dehydration systems which use a solid desiccant. ARB and WCI recommend adopting the proposed U.S. EPA draft methodologies with very minor modification to Equation W-6 in the U.S. EPA proposed Subpart W. This equation has been modified by removing the time between filling terms. Operators simply calculate emissions for each venting/filling cycle.

Summary of Section 95153(d)(1).
This provision establishes reporting requirements for input into the simulation software package GRI-GLYCalc Version 4.

Rationale for Section 95153(d)(1).
This provision is necessary because minimum data input requirements are needed to ensure data quality and consistency.

Summary of Section 95153(d)(2).
This provision directs reporters to emission calculation methodologies for dehydrator vent emissions which are routed to flares or used as fuel.

Rationale for Section 95153(d)(2).
This provision is necessary to ensure that all emissions from dehydrator vent stacks are reported.

Summary of Section 95153(d)(3).
This provision establishes reporting requirements for reporters at facilities where desiccant dehydrators are employed.

Rationale for Section 95153(d)(3).
This provision is necessary because an emissions methodology is required for facilities where desiccant dehydrators are used.

Summary for Section 95153(e), Well Venting for Liquids Unloadings.
This provision establishes reporting requirements for emissions that result when a gas well is vented to the atmosphere to remove accumulated water and restore gas flow. These emissions may be substantial as typically gas wells may be vented for hours as the well gas flow is used to expel the accumulated water in the well.

Rationale for Section 95153(e).
This provision is necessary to inform operators which calculation methodology they must use. U.S. EPA has provided two calculation methods. Method one allows operators to calculate well venting emissions for each unique well tubing diameter and producing horizon/formation combination in each gas producing field. This data is then used with the total venting time for all similar wells. Method two requires operators calculate emissions from each well venting episode. WCI and ARB have concluded that method two provides more rigorous and accurate data. Therefore, operators must use the more accurate Method 2.

Summary for Section 95153(f), Gas Well Venting During Unconventional Well Completions and Workovers.
This provision defines unconventional wells as those wells where hydraulic fracturing has been employed to enhance gas production volumes. The U.S. EPA proposed methodology requires that operators calculate CO_2 and CH_4 emissions by measuring the time and gas flow rate during the period when the well is open to atmospheric during the venting process. Currently there are no EOR operations in California which employ fracking technology - there are no unconventional wells in California at this time. This methodology is included in the proposed regulation with no changes from the U.S. EPA draft Subpart W.

Rationale for Section 95153(f).
This provision is necessary in order to provide reporters with a methodology to calculate emissions from unconventional well completions and workovers

Summary of Section 95153(f)(1).
This provision establishes a reporting method for natural gas well venting during unconventional well completions and blowdowns.

Rationale for Section 95153(f)(1).
This provision is necessary because a methodology must be provided to quantify these emissions.

Summary of Section 95153(f)(2).
This provision directs reporters to methods for converting natural gas emissions to standard temperature and pressure.

Rationale for Section 95153(f)(2).
This provision is necessary to provide a method for operators to calculate GHG volume and mass emissions.

Summary of Section 95153(f)(3).
This provision directs reporters to methods for converting natural gas volume emissions at standard temperature and pressure to mass emissions.

Rationale for Section 95153(f)(3).
This provision is necessary because natural gas volume emissions must be converted to mass emissions prior to calculating GHG mass and volume emissions.

Summary of Section 95153(f)(4).
This provision establishes calculation methodologies for measurement of gas flow rates during well completions and workovers.

Rationale for Section 95153(f)(4).
This provision is necessary because standard methods must be required to ensure data accuracy and consistency.

Summary for Section 95153(g), Gas Well Venting During Conventional Well Completions and Workovers.
This provision requires operators to determine CO_2 and CH_4 emissions for each well completion and well workover using the daily gas production rate and cumulative time of well venting. This method has been included with no modifications from the proposed U.S. EPA draft Subpart W method.

Rational for Section 95153(g).
This provision is necessary to provide methods for conventional wells which do not employ hydraulic fracturing to enhance gas production. When conventional wells are drilled and worked over, emissions of CO_2 and CH_4 can be significant as the well is vented to the atmosphere.

Summary for Section 95153(h), Blowdown Vent Stacks.
This provision requires operators to calculate emissions from equipment blowdowns where natural gas is vented to the atmosphere. Operators must calculate the total volume which is vented and record the number of each unique equipment blowdowns per reporting period. If these emissions are flared, operators must use the method in Section 95153(l) to calculate flaring emissions. This method is included with no changes from the proposed U.S. EPA Subpart W calculation scheme.

Rationale for Section 95153(h).
This provision is necessary because blowdowns of equipment such as natural gas compressors represents a significant source of methane and CO_2 emissions.

Summary of Section 95153(h)(1).
This provision requires operators to calculate the volume of compressors which are blowndown (the variable V).

Rationale for Section 95153(h)(1).
This provision is necessary because this provision ensures that all blowdown volumes are determined.

Summary of Section 95153(h)(2).
This provision requires operators to maintain blowdown logs for each equipment type.

Rationale for Section 95153(h)(2).
This provision is necessary because logging of blowdown events is required to calculate blowdown emissions.

Summary of Section 95153(h)(3).
This provision establishes the calculation method for equipment blowdowns.

Rationale for Section 95153(h)(3).
This provision is necessary to ensure data consistency and accuracy.

Summary of Section 95153(h)(4).
This provision provides a method for natural gas volume conversion to standard temperature and pressure prior to calculating GHG emissions.

Rationale for Section 95153(h)(4).
This provision is necessary to ensure data quality and consistency.

Summary of Section 95153(h)(5).
This provision directs reporters to the sections of the regulation which detail conversion of natural gas volumes to GHG volume and mass emissions.

Rationale for Section 95153(h)(5).
This provision is necessary to ensure data quality and consistency.

Summary of Section 95153(i), Onshore Production and Processing Storage Tanks.
This provision provides two methods for the calculation of methane and CO_2 emissions from crude and condensate storage tanks. Method one must be used for storage tanks where the oil production rate is 10 bbl/day or less. In this case operators must use the E&P Tank software simulation package to estimate emissions. For storage tanks where the oil production rate is greater than 10 bbl/day, operators must collect a pressurized

sample at a location between the last separator and the storage tank, and determine the GOR and the methane content of the evolved gas. Method two assumes that all the methane released during the determination of GOR will be vented to the atmosphere as the crude/condensate product stabilizes after production.

<u>Rationale for Section 95153(j)</u>.
This provision is necessary to provide consistency with U.S. EPA's proposed Subpart W where possible. It is also necessary because WCI and ARB concluded that actual measurement of GOR will provide a more accurate estimate of emissions. Thus method two is required for all storage tanks where production is above10 bbl/day.

<u>Summary of Section 95153(i)(1)</u>.
This provision establishes reporting methods for storage tanks where oil production rates are 10 barrels per day or less.

<u>Rationale for Section 95153(i)(1)</u>.
This provision is necessary to provide operators with the methodology to calculate storage tank emissions from production storage tanks where production is equal to or less than 10 barrels per day.

<u>Summary of Section 95153(i)(2)</u>.
This provision establishes reporting methods for storage tanks where oil production rates are greater than 10 barrels per day.

<u>Rationale for Section 95153(i)(2)</u>.
This provision is necessary to provide operators with the methodology to calculate storage tank emissions from production storage tanks where production greater than 10 barrels per day.

<u>Summary of Section 95153(j), Well Testing and Flaring</u>.
This provision requires that operators determine well venting and flaring emissions by determining the GOR of the hydrocarbon production from the well, the flow rate of oil per day, and the number of days per reporting period that the well was tested. If these emissions are flared, operators must use the method in Section 95153(l) to calculate flaring emissions.

<u>Rationale for Section 95153(j)</u>.
This provision is necessary because when wells are tested to determine production characteristics the well may be opened to atmospheric pressure. Thus, significant emissions of CH_4 and CO_2 can be significant during well testing. This method has been adopted from the draft U.S. EPA Subpart W without changes. The methodology for the calculation of flaring emissions has been modified to address errors identified in the draft U.S. EPA methodology (see Section 95153(l) below).

Summary of Section 95153(j)(1).
This provision provides operators with details on sampling which must be conducted at each well.

Rationale for Section 95153(j)(1).
This provision is necessary because operators must understand what sampling is required.

Summary of Section 95153(j)(2).
This provision establishes the calculation method for this emission source.

Rationale for Section 95153(j)(2).
This provision is necessary because a standard method for calculating emissions is required to ensure data consistency and accuracy.

Summary of Section 95153(j)(3).
This provision directs reporters to the appropriate section where methods for conversion of natural gas volumes to standard temperature and pressure are located.

Rationale for Section 95153(j)(3).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(j)(4).
This provision directs reporters to the appropriate sections of this regulation where methods for conversion of natural gas volume data to GHG mass emissions are located.

Rationale for Section 95153(j)(4).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(j)(5).
This provision directs reporters to the appropriate section where methods for calculating flaring emissions are detailed.

Rationale for Section 95153(j)(5).
This provision is necessary because a standard methodology for the calculation of flaring emissions is required to ensure data consistency and quality.

Summary for Section 95153(k), Associated Gas Venting and Flaring.
This provision requires that operators determine associated gas well venting and flaring emissions by determining the GOR of the hydrocarbon production from the well and the total volume of oil produced per day for the well being tested. If these emissions are flared, operators must use the method in Section 95153(l) to calculate flaring emissions.

Rationale for Section 95153(k).
This provision is necessary because in cases where small amounts of associated gas may be stranded (there is no access to a gas pipeline), this gas may be vented or flared, resulting in significant methane and CO_2 emissions. This method has been adopted from the draft U.S. EPA Subpart W without changes. The methodology for the calculation of flaring emissions has been modified to address errors identified in the draft U.S. EPA methodology (see Section 95153(l) below).

Summary of Section 95153(k)(1).
This provision details sampling which must be conducted at each well.

Rationale for Section 95153(k)(1).
This provision is necessary to ensure that operators understand what sampling is required.

Summary of Section 95153(k)(2).
This provision establishes the calculation method for this emission source.

Rationale for Section 95153(k)(2).
This provision is necessary because a standard method for calculating emissions is required to ensure data consistency and accuracy.

Summary of Section 95153(k)(3).
This provision directs reporters to the appropriate sections of the regulation where methods for conversion of natural gas volumes to standard temperature and pressure are located.

Rationale for Section 95153(k)(3).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(k)(4).
This provision directs reporters to the appropriate sections of the regulation where methods for conversion of natural gas volume data to GHG mass emissions are located.

Rationale for Section 95153(k)(4).
This provision is necessary because a standard method for calculating emissions is required to ensure data consistency and accuracy.

Summary of Section 95153(k)(5).
This provision directs reporters to the appropriate section of the regulation where methods for calculating flaring emissions are detailed.

Rationale for Section 95153(k)(5).
This provision is necessary because a standard methodology for the calculation of flaring emissions is required to ensure data consistency and quality.

Summary of Section 95153(l), Flare Stacks.
This provision sets forth reporting requirements and methods for emissions related to flaring of produced gas. Methodologies are included for calculating un-combusted methane emissions, pass through CO_2 emissions, and combusted emissions. In cases where vented and process emissions are captured and directed to a flare, reporters must use the calculation methods in this section.

Rational for Section 95153(l).
This provision is necessary because flares may be used to combust emissions from many sources such as equipment blowdowns, well testing, stranded gas, and storage tank vapor recovery. The U.S. EPA methodologies have been adopted with modifications to correct errors identified during the WCI harmonization process.

Summary of Section 95153(l)(1).
This provision establishes flare flow measurement requirements for this section.

Rationale for Section 95153(l)(1).
This provision is necessary to enable operators to determine flow to each flare.

Summary of Section 95153(l)(2).
This provision establishes gas composition measurement requirements for this section.

Rationale for Section 95153(l)(2).
This provision is necessary to enable operators to determine gas composition for each stream sent to each flare.

Summary of Section 95153(l)(3).
This provision establishes criteria for determining flare destruction efficiency

Rationale for Section 95153(l)(3).
This provision is necessary because a standard methodology for the determination of flare destruction efficiency is required to ensure data consistency and quality.

Summary of Section 95153(l)(4).
This provision directs reporters to section 95115 to access methods for calculating stationary combustion emissions.

Rationale for Section 95153(l)(4).
This provision is necessary because a standard method for calculation of all stationary combustion promotes data consistency and quality.

Summary of Section 95153(l)(5).
This provision contains methods for calculation of flare stack methane emissions and CO_2 combustion emissions.

Rationale for Section 95153(l)(5).
This provision is necessary to inform operators of the specific emissions calculation methods required to calculate methane and CO_2 flare combustion emissions.

Summary of Section 95153(m), Centrifugal Compressor Wet Seal Degassing Vents.
This provision contains methodologies for the calculation of methane emissions which result when oil used to provide a seal in natural gas compressors is purged of dissolved gas. Operators must determine both the wet seal degassing venting rates per unit time and mole fraction of CO_2 and CH_4 in the degassing emissions semi-annually and record the operational time for each degassing unit. If degassing vent emissions are captured and sent to a flare operators must use the flare stack emissions methodology (95153(l)) to estimate these flaring emissions.

Rationale for Section 95153(m).
This provision is necessary because emissions resulting from degassing of oil used to lubricate centrifugal compressor wet seals are recognized to be major source of vented emissions for natural gas compression. These emissions from wet seal oil degassing units may be vented directly into the atmosphere or captured and sent to a flare and this methodology covers each of these contingencies. The draft U.S. EPA methodology did not include a sampling frequency for the measurement of wet seal degassing vent emission rates and GHG mole fraction. Thus ARB has added a requirement to measure these two variables semi-annually. Otherwise, this methodology is unchanged from the U.S. EPA draft Subpart W method.

Summary of Section 95153(m)(1).
This provision establishes measurement requirements for this section.

Rationale for section 95153(m)(1).
This provision is necessary because standard measurement methods ensure data consistency and quality.

Summary of Section 95153(m)(2).
This provision establishes calculation methods for this source.

Rationale for section 95153(m)(2).
This provision is necessary because standard calculation methods ensure data consistency and quality.

Summary of Section 95153(m)(3).
This provision directs reporters to the appropriate section of the regulation where methods for conversion of natural gas volumes to standard temperature and pressure are located.

Rationale for section 95153(m)(3).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(m)(4).
This provision directs reporters to the appropriate sections of the regulation where methods for conversion of natural gas volume data to GHG mass emissions are located.

Rationale for section 95153(m)(4).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(m)(5).
This provision directs reporters to the appropriate section of the regulation where methods for calculating flaring emissions are detailed.

Rationale for section 95153(m)(5).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(n), Reciprocating Compressor Rod Packing Venting.
This provision presents methodologies for the calculation of vented emissions from leaks in reciprocating compressor rod packing material.

Rationale for Section 95153(n).
This provision is necessary because leaks from reciprocating compressor rod packing are a very important source of fugitive methane emissions in the natural gas processing, transmission, and storage sectors. Rod packing emissions vary with the mode of compressor operation, thus it is important that emissions estimates be made in both operating and standby-pressurized modes. The methodology in this proposed regulation has been adopted without change from the U.S. EPA Subpart W draft.

Summary of Section 95153(n)(1).
This provision establishes emission calculation methods for this emission source.

Rationale for section 95153(n)(1).
This provision is necessary because a standard calculation method is required to ensure data consistency and accuracy.

Summary of Section 95153(n)(2).
This provision details the required measurement method for venting directed to an open ended vent line.

Rationale for section 95153(n)(2).
This provision is necessary because emissions may be directed to an open ended line and thus a consistent method of measuring these emissions is needed.

Summary of Section 95153(n)(3).
This provision details the required measurement method for venting not directed to an open ended vent line.

Rationale for section 95153(n)(3).
This provision is necessary because emissions may be vented directly and thus a consistent method of measuring these emissions is needed.

Summary of Section 95153(n)(4).
This provision requires operators to conduct measurements for three operational modes: (1) operating, (2) standby, pressurized, and (3) not operating, depressurized.

Rationale for section 95153(n)(4).
This provision is necessary to ensure emissions measurements are made in all operational modes where emissions occur.

Summary of Section 95153(n)(5).
This provision directs reporters to the appropriate section of the regulation where methods for conversion of natural gas volumes to standard temperature and pressure are located.

Rationale for section 95153(n)(5).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(n)(6).
This provision directs reporters to the appropriate sections of the regulation where methods for conversion of natural gas volume data to GHG mass emissions are located.

Rationale for section 95153(n)(6).
This provision is necessary because a standard conversion method is required to ensure data consistency and accuracy.

Summary of Section 95153(o), Leak Detection and Leaker Emission Factors (reporting only).
This provision details a screening/emission factor methodology for the semi-quantitative determination of fugitive emissions. Operators are required to screen components and apply a default emissions factor to all components which are identified as “leakers”.

Rationale for Section 95153(o).
This provision is necessary because fugitive emissions are by their nature, difficult to quantify. Methodologies such as hi-volume samplers and calibrated bags do provide quantitative information on component leak rates. However, these methods are expensive and labor intensive. Additionally, once a leaking component has been identified and the emission rate measured, one must estimate the length of time over which the component has been leaking – a difficult task. While the proposed method provides only semi-quantitative data which is for classified as “reporting only emissions” (no compliance obligation), the proposed method does provides operators with actionable information concerning which components are leaking and the relative order of magnitude estimate of leak rates.

Summary of Section 95153(o)(1).
This provision requires that operators report GHG emissions at standard temperature and pressure.

Rationale for Section 95153(o)(1).
This provision is necessary to ensure all GHG emissions are reported consistently.

Summary of Section 95153(o)(2).
This provision directs operators to the appropriate emission factors for affected components at natural gas processing facilities.

Rationale for Section 95153(o)(2).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(o)(3).
This provision directs operators to the appropriate emission factors for affected components at onshore natural gas transmission compression facilities.

Rationale for Section 95153(o)(3).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(o)(4).
This provision directs operators to the appropriate emission factors for affected components at underground natural gas storage facilities.

Rationale for Section 95153(o)(4).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(o)(5).
This provision directs operators to the appropriate emission factors for affected components at LNG storage facilities.

Rationale for Section 95153(o)(5).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(o)(6).
This provision directs operators to the appropriate emission factors for affected components at LNG import and export facilities.

Rationale for Section 95153(o)(6).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(o)(7).
This provision directs operators to the appropriate emission factors for affected components at natural gas distribution facilities.

Rationale for Section 95153(o)(7).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(p), Population Count and Emission Factors (reporting only).
This provision requires that operators simply conduct a component count and apply a default emissions factor for each component type. These emissions are classified as "reporting only emissions" and thus do not carry a compliance obligation.

Rationale for Section 95153(p).
This provision is necessary because the method provides semi-quantitative information on leaking components. Given the small size of these emissions on a facility basis, the use of expensive and labor intensive quantitative emissions measurement techniques is not justified, especially given the inherent difficulty in determining leak duration.

Summary of Section 95153(p)(1).
This provision directs operators to the appropriate sections of the regulation where methods for conversion of natural gas volume data to GHG mass emissions are located.

Rationale for Section 95153(p)(1).
This provision is necessary because a standard calculation method is required to ensure data consistency and accuracy.

Summary of Section 95153(p)(2).
This provision directs operators to the appropriate emission factors for affected components at onshore petroleum and natural gas production facilities.

Rationale for Section 95153(p)(2).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(p)(3).
This provision directs operators to the appropriate emission factors for affected components at onshore natural gas processing facilities.

Rationale for Section 95153(p)(3).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(p)(4).
This provision directs operators to the appropriate emission factors for affected components at underground natural gas storage facilities

Rationale for Section 95153(p)(4).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(p)(5).
This provision directs operators to the appropriate emission factors for affected components at LNG storage facilities.

Rationale for Section 95153(p)(5).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(p)(6).
This provision directs operators to the appropriate emission factors for affected components at LNG import and export facilities.

Rationale for Section 95153(p)(6).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(p)(7).
This provision directs operators to the appropriate emission factors for affected components at natural gas distribution facilities.

Rationale for Section 95153(p)(7).
This provision is necessary to enable operators to use the correct emissions factors.

Summary of Section 95153(q), Offshore Petroleum and Natural Gas Production Facilities in both State and Federal Waters (reporting only).
This provision requires that operators of offshore petroleum and natural gas production facilities use methods contained in the Mineral Management Service (MMS) Gulfwide Offshore Activity Data System (GOADS) reporting program (GOADS 2005). It also provides operators who have not formerly reported using GOADS with the specific requirements they must follow.

Rationale for Section 95153(q).
This provision is necessary to maintain consistency with the U.S. EPA draft Subpart W. California offshore facilities have not previously reported emissions to MMS because participation in the GOADS program was required only for petroleum and natural gas production platforms located in the Gulf of Mexico. This reporting requirement extends this requirement to California off-shore platforms and informs them what GOADS requirements must be met.

Summary of Section 905153(r), Volumetric Emissions.
This provision provides a standard method for the conversion of volumetric natural gas emissions to standard temperature and temperature conditions. Operators must determine the ambient temperature and pressure condition under which volumetric emissions were made.

Rational for Section 95153(r).
This provision is necessary to enable operators to consistently calculate natural gas emissions at ambient conditions. These ambient measurements must first be converted to a standard temperature and pressure before volumetric and mass GHG emissions can be calculated.

Summary of Section 95153(r)(1).
This provision establishes a calculation method for conversion of natural gas volumetric emissions at ambient conditions to a standard temperature and pressure.

Rationale for Section 951539(r)(1).
This provision is necessary because standardized conversion equations are provided to help ensure data consistency and as a reporting aid.

Summary of Section 95153(r)(2).
This provision establishes a calculation method for conversion of GHG emissions at ambient conditions to GHG volumetric emissions at standard conditions.

Rationale for Section 951539(r)(2).
This provision is necessary because standardized conversion equations are provided to help ensure data consistency and as a reporting aid.

Summary of Section 95153(s), GHG Volumetric Emissions.
This provision provides a standard method for converting natural gas volumetric emissions to GHG volumetric emissions. Operators must determine the mole percent of each GHG in the natural gas.

Rationale for Section 95153(s).
This provision is necessary because a standard method for converting natural gas volumetric emissions to GHG volumetric emissions to ensure data consistency. Volumetric GHG emission must then be converted to mass GHG emissions as prescribed in the following section. Inclusion of this method will promote data consistency as they provide a standard method for this conversion.

Summary of Section 95153(s)(1).
This provision establishes a standard method for calculating CH_4 and CO_2 emissions from natural gas

Rationale for Section 95153(s)(1).
This provision is necessary because standardized conversion equations are provided to help ensure data consistency and as a reporting aid.

Summary of Section 95153(s)(2).
This provision directs operators to measure GHG mole percent of natural gas for each of the effected sectors.

Rationale for Section 95153(s)(2).
This provision is necessary to enable operators to measure the GHG percent of natural gas as defined in this section.

Summary of Section 95153(t), GHG Mass Emissions.
This provision provides a standard method for the conversion of GHG volumetric emissions to GHG mass emissions. Operators are not required to determine any additional information.

Rational for Section 95153(t).
This provision is necessary because this standard method for conversion of GHG volumetric emissions to GHG mass emissions provides data consistency and reduces the potential for calculation error.

Summary of Section 95153(u), EOR Injection Pump Blowdown.
Enhanced Oil Recovery CO_2 pumps must be blown-down periodically. This provision provides operators with a method to calculate CO_2 emissions which occur when an EOR CO_2 injection pump is blown-down.

Rationale for Section 95153(u).
This provision is necessary because while EOR activities in California are currently limited to water flood and thermal (steam) technologies, CO_2 based EOR may be employed in the State in the future. This method has been included without modification from the U.S. EPA draft Subpart W.

Summary of Section 95153(u)(1).
This provision directs operators to calculate the total blowdown volume for EOR injection pump blowdowns.

Rationale for Section 95153(u)(1).
This provision is necessary to enable operators to consistently calculate the variable "total volume of equipment blowdown chambers."

Summary of Section 95153(u)(2).
This provision requires reporters maintain a logs of the number of blowdowns in the reporting year.

Rationale for Section 95153(u)(2).
This provision is necessary because it enables operators to establish the total number of blowdowns, the variable N, which is required for emissions calculation.

Summary of Section 95153(u)(3).
This provision establishes the calculation methodology for this emission source.

Rationale for Section 95153(u)(3).
This provision is necessary to enable operators to consistently calculate emissions from EOR injection pump blowdowns.

Summary of Section 95153(v), Produced Water Dissolved CO_2.
This provision provides a method for the calculation of emissions from CO_2 retained in produced water. Operators are required to determine the amount of CO_2 dissolved in produced water quarterly.

Rationale for Section 95153(v).
This method has been included without modification from the U.S. EPA draft Subpart W. This provision is necessary because emissions of CO_2 from produced water represents on one of three reservoirs from which this entrained CO_2 may be emitted – produced hydrocarbons, produced water, or produced natural gas.

Summary of Section 95153(v)(1).
This provision establishes the sampling frequency and location for this source.

Rationale for Section 95153(v)(1).
This provision is necessary because standard sampling intervals and locations ensure data quality and consistency.

Summary of Section 95153(v)(2).
This provision details the calculation methodology for this emissions source.

Rationale for Section 95153(v)(2).
This provision is necessary to enable operators to calculate emissions for this source.

Summary of Section 95153(v)(3).
This provision states that operations that re-inject produced water directly into the hydrocarbon reservoir are not required to report emissions under this section.

Rationale for Section 95153(v)(3).
This provision is necessary to inform operators which operations are not required to report. Direct re-injection of produced water will not result in emissions.

Summary of Section 95153(w), Portable Equipment Combustion Emissions.
This provision requires that operators report all emissions from portable equipment that is deployed at a facility using methods described in section 95115 of this article.

Rationale for Section 95153(w).
This provision is necessary to ensure that all emissions associated with the exploration, well drilling, and production phases are reported. This requirement promotes data consistency across reporting entities where varying fractions of emissions are generated by operations conducted by contracted personnel.

Summary of Section 95154, Monitoring and QA/QC Requirements.

Summary of Section 95154(a).
This provision harmonizes monitoring, data and records requirements with the provisions for reporting of GHG emissions from this sector. This section requires that operators meet applicable requirements for monitoring, missing data procedures, data reporting and records retention.

Rationale for Section 95154(a).
This provision is necessary because this information is required input in the verification process for reported facility emissions. An accurate verification is a cornerstone of an effect GHG reporting and mitigation program.

Summary of Section 95154(a)(1).
This provision directs operators to sampling criteria for the optical gas instrument which is used to conduct leak detection.

Rationale for Section 95154(a)(1).
This provision is necessary because the use of a standard instrument operating protocol promotes data accuracy and data quality.

Summary of Section 95154(a)(2).
This provision directs operators to follow standard methods for meter, analyzer and pressure gauge calibration during the first and subsequent years.

Rationale for Section 95154(a)(2).
This provision is necessary because standard methods and intervals for instrument calibration promote data accuracy and consistency.

Summary of Section 95154(a)(3).
This provision sets forth requirements for the use of calibrated bags.

Rationale for Section 95154(a)(3).
This provision is necessary because standard methods for conducting leak measurements promote data accuracy and consistency.

Summary of Section 95154(b).
This provision establishes standard procedures for the use of a high volume sampler which must be used to measure leak emissions.

Rationale for Section 95154(b).
This provision is necessary because standard methods for conducting leak measurements promote data accuracy and consistency.

Summary of Section 95154(b)(1).
This provision provides operating instructions for the use of a high volume sampler.

Rationale for Section 95154(b)(1).
This provision is necessary because standard methods for conducting leak measurements promote data accuracy and consistency.

Summary of Section 95154(b)(2).
This provision establishes high volume sampler operating procedures in cases where the sampler is not capable of capturing all the emissions.

Rationale for Section 95154(b)(2).
This provision is necessary because standard methods for conducting leak measurements promote data accuracy and consistency.

Summary of Section 95154(b)(3).
This provision directs operators to the appropriate method for calculating GHG volumetric and mass emissions from volumetric natural gas emissions.

Rationale for Section 95154(b)(3).
This provision is necessary because conversion of natural gas volumetric emissions to GHG volumetric and mass emissions is required in this section. Standard conversion methods promote data accuracy and consistency.

Summary of Section 95154(b)(4).
This provision establishes calibration requirements for the high volume sampler.

Rationale for Section 95154(b)(4).
This provision is necessary because standard methods for instrument calibration promote data accuracy and consistency.

Summary of Section 95155, Procedures for Estimating Missing Data.

Summary of Section 95155(a).
This provision establishes missing data substitution procedures for operators in the petroleum and natural gas system sector.

Rationale for Section 95155(a).
This provision is necessary because these missing data substitution procedures are designed to provide a strong incentive for reporters to generate as complete a data set

as possible, while specifying how to generate substitution data in circumstances where data was unavoidably lost.

Summary of Section 95156, Data Reporting Requirements.

This provision modifies data reporting requirements to match the modified sampling and reporting frequencies. It also provides operators with a reporting method that avoids double-counting emissions that have been included elsewhere in the facility report.

Rationale for Section 95156.
This provision is necessary because an accurate GHG accounting procedure must avoid double-counting of emissions.

Summary of Section 95156(a).
This provision establishes data reporting requirements for each industry segment required to report by this MRR.

Rationale for Section 95156(a).
This provision is necessary because operators must report all required emissions as well as supporting data. Standard reporting procedures for all sources promotes data quality and consistency.

Summary of Section 95156(b).
This provision requires operators to report emissions separately for standby equipment.

Rationale for Section 95156(b).
This provision is necessary because operators must report all required emissions as well as supporting data. Standard reporting procedures for all sources promotes data quality and consistency.

Summary of Section 95156(c).
This provision establishes data reporting requirements for additional aggregated source types.

Rationale for Section 95156(c).
This provision is necessary because operators must report all required emissions as well as supporting data. Standard reporting procedures for all sources promotes data quality and consistency.

Summary of Section 95156(d).
This provision requires operators to report minimum, maximum, and average throughput for each operation listed in paragraphs (a)(1) through (a)(8) of this section.

Rationale for Section 95156(d).
This provision is necessary because operators must report all required emissions as well as supporting data. Standard reporting procedures for all sources promotes data quality and consistency.

Summary of Section 95156(e).
This provision requires operators to report the number of connected wells and whether the wells are producing oil, gas, or both.

Rationale for Section 95156(e).
This provision is necessary because operators must report all required emissions as well as supporting data. Standard reporting procedures for all sources promotes data quality and consistency.

Summary of Section 95156(f).
This provision requires operators to report emissions separately for portable equipment for drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters.

Rationale for Section 95156(f).
This provision is necessary because operators must report all required emissions as well as supporting data. Standard reporting procedures for all sources promotes data quality and consistency.

Summary of Section 95157, Records that Must be Retained.

This provision requires operators to retain records on the date of measurements, the results of emissions detection and measurement, of calibration reports, and on the inputs and outputs of calculations or emission computer model pursuant to section 95105 of this article.

Rational for Section 95157.
This provision is necessary because data retention requirements must match data reporting requirements to ensure that comprehensive report verification may be conducted. Moreover, this information is needed for data verification purposes.

Summary of Section 95158, Data Tables.

This provision contains seven data tables containing default emissions factors.

Rationale for Section 95158.
This provision is necessary in order to provide operators with the default emissions factors they are required to use to comply with the regulation.

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