California Environmental Protection Agency
Air Resources Board

Final Statement of Reasons for Rulemaking

Including Summary of Comments and Agency Responses

PUBLIC HEARING TO CONSIDER ADOPTION OF
A REGULATION FOR THE

MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

Public Hearing Date: December 6, 2007
Agenda Item No. 07-12-3

October 2008

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I.

INTRODUCTION

In this rulemaking, the Air Resources Board (ARB or Board) has adopted a new regulation that provides for the mandatory reporting of greenhouse gas (GHG) emissions from large sources. The regulation specifies the types of facilities that must report their GHG emissions, requirements for reporting and estimating the GHG emissions, and requirements for emissions verification. The regulation was developed pursuant to the requirements of the California Global Warming Solutions Act of 2006, also known as Assembly Bill 32 (the Act or AB 32). The regulation is codified at sections 95100 to 95133, title 17, California Code of Regulations (CCR).

On October 19, 2007, ARB issued a notice of public hearing to consider the proposed regulation at the Board's December 6, 2007 hearing. A "Staff Report: Initial Statement of Reasons for Rulemaking" (Staff Report or ISOR) was also made available for public review and comment starting October 19, 2007. The Staff Report, which is incorporated by reference herein, described the rationale for the proposal. The text of the proposed regulation was included as Appendix A to the Staff Report. These documents were also posted on the ARB's internet web site at:
http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm

On December 6, 2007, the Board conducted a public hearing to consider the staff's proposal for adoption. Written and oral comments were received at the hearing. At the same hearing, the staff presented modifications to the regulation as originally proposed in the Staff Report in response to comments received since the staff report was published. The Board adopted Resolution 07-54, approving the proposed regulation for adoption with the modifications proposed by staff. The Board also directed staff to modify the emissions verification schedule to remove a one-year delay initially provided for some facilities subject to a triennial verification schedule. Resolution 07-54 directed the Executive Officer to adopt the modified regulations after making the modified regulatory language available for public comment for a period of at least 15 days, in accordance with Government Code section 11346.8(c), and to make such additional modifications as may be appropriate in light of the comments received, or to present the regulation to the Board for further consideration if warranted in light of the comments.

A "Notice of Public Availability of Modified Text" together with a copy of the full text of the regulation modifications, with the modifications clearly indicated, was provided to the public and affected stakeholders on May 15, 2008 for a comment period from May 15, 2008, to June 5, 2008, pursuant to Government Code section 11346.8. Based on comments received, a second 15-day comment period with additional revisions to the regulation was provided for public comment. This second "Notice of Public Availability of Modified Text" and the regulation modifications were released on June 30, 2008, with the deadline for public comments of July 15, 2008.

This Final Statement of Reasons for Rulemaking (FSOR) updates the Staff Report by identifying and explaining the modifications that were made to the original proposal. The FSOR also summarizes the written and oral comments received during the rulemaking process, and contains ARB's responses to those comments. Modifications to the original proposal are described in Section II of this FSOR entitled "Modifications Made to the Original Proposal."

The Executive Officer issued Executive Order No. R-08-008 on October 12, 2008, adopting the regulation with the modifications described in Section II of this FSOR.

Fiscal Impacts on Local Government and School Districts

The Executive Officer has determined that the proposed regulatory action will result in nondiscretionary costs for local agencies (if they operate the type of facility that is required to report), and may impose a mandate, as defined in Government Code section 17514. However, the mandate is not reimbursable by the state pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code, because the costs would apply to all operators of covered facilities, not just local agencies. The Board has also determined that this regulatory action will not create costs or impose a mandate upon any school district, whether or not it is reimbursable by the State pursuant to Part 7 (commencing with section 17500), division 4, title 2 of the Government Code.

The local public agencies that will be affected include an estimated 30 to 60 cities, counties, public utility districts, and other agencies that operate publicly owned utilities or maintain facilities such as certain landfills or certain sewage treatment plants. The combined annual costs to these local agencies during the first two years of the regulation is estimated in the Staff Report at $120,000 to $800,000, with a midpoint cost estimate of $460,000 and a per-facility annual cost range of $3,000 to $20,000. Annual reporting costs to local agencies are expected to decline after the first two years of implementation.

Incorporation by Reference

The following documents and test methods are incorporated by reference in the regulation:

(a) American Society for Testing and Materials (ASTM) D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), ASTM D240-02 (Reapproved 2007), ASTM D4809-00 (Reapproved 2005), ASTM 5373-02 (Reapproved 2007), ASTM D5291-02 (Reapproved 2007), ASTM D3238-95 (Reapproved 2005), ASTM D2502-04, ASTM D2503-92 (Reapproved 2002), ASTM D1945-03, ASTM D1946-90 (Reapproved 2006), ASTM D6866-06a, ASTM D388-05, ASTM D5468-02 (Reapproved 2007), ASTM D240-87 (Reapproved 1991), ASTM D5865-07a, ASTM Specification D396-07, ASTM Specification D975-07b.

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

(c) *Control of Emissions from Refinery Flares*, Rule 118, South Coast Air Quality Management District, Amended November 4, 2005.

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

(e) Gas Processors Association (GPA) Standard 2261-00, Revised 2000.

These documents were incorporated by reference because it would be cumbersome, unduly expensive, and otherwise impractical to publish them in the California Code of Regulations (CCR). The documents are lengthy and highly technical test methods and engineering documents that would add unnecessary additional volume to the regulation. Distribution to all recipients of the CCR is not needed because the interested audience for these documents is limited to the technical staff at a portion of reporting facilities, most of whom are already familiar with these methods and documents. In addition, the incorporated documents were made available by ARB upon request during the rulemaking action and will continue to be available in the future. The documents are also commonly available from college and public libraries, or may be purchased directly from the publishers.

Consideration of Alternatives

The regulation was the subject of discussions involving staff, representatives of the affected businesses and agencies, and other interested members of the public. A discussion of alternatives to the initial regulatory proposal is found in Chapter VII of the Staff Report. For the reasons set forth in the Staff Report, in staff's comments and responses at the hearing, and in this FSOR, the Board has determined that none of the alternatives identified and brought to the attention of the agency or otherwise considered by the agency would be more effective in carrying out the purpose for which the regulatory action was proposed, or would be as effective and less burdensome to affected private persons, than the action taken by the Board.

ARB rejected two changes in the regulations that were suggested in public comments for the purpose of reducing the regulation's economic impact on small businesses. One proposal was to allow small businesses to defer reporting of fugitive and combustion emissions for two years, until 2011. The other proposal was to exempt small businesses from the requirement that emissions data reports be subject to verification by third parties. In both instances, ARB rejected the proposals to reduce small business economic impacts because they would have compromised the collection of full and accurate data. See comments B-41 and E-3 and ARB's responses to those comments for additional information. ARB notes that these changes were proposed in part to benefit oil and gas producers and refiners, but these businesses are expressly excluded from the Administrative Procedure Act's definition of "small business" regardless of size. See Government Code section 11342.610(b)(9).

II.

MODIFICATIONS MADE TO THE ORIGINAL PROPOSAL

Various modifications were made to the original proposal to address comments received during the 45-day public comment period, and to clarify the regulatory language. These modifications are described below. In addition, the Board directed staff to modify the emissions verification schedule to remove a one-year delay initially provided for some facilities subject to a triennial verification schedule. A Notice of Public Availability of Modified Text, together with a copy of the mandatory reporting regulation with changes indicated, was posted on May 15, 2008, for period of public review and comment through June 5, 2008. A Second Notice of Public Availability of Modified Text, together with a copy of the mandatory reporting regulation with additional changes indicated, was posted on June 30, 2008, for a period of public review and comment through July 15, 2008. For each of these postings, notification was sent to persons who have expressed interest in the regulation during the course of rule development and review, including all individuals described in subsections (a)(1) through (a)(4) of section 44, Title 1, CCR. By these actions, the modified regulations were made available to the public for supplemental comments periods pursuant to Government Code section 11346.8.

First Availability of Modified Text
Modifications to the regulations originally published October 19, 2007, were made available to the public for comment on May 15, 2008. The major changes are summarized below.

General Provisions, §95100 – §95109

- Applicability language was modified to further clarify what facilities will be subject to the regulation. These modifications include the addition of an emissions threshold for petroleum refineries, geographical and ownership/operational limitations for certain facilities covered by the regulations, and clarification as to the years on which the emissions thresholds are based. (§95101)
- An exemption from the regulation's requirements for designated backup generators was modified to apply also to designated emergency generators. (§95101)
- Definitions were added for the following terms: accuracy, CAISO, California Energy Commission, carbon dioxide equivalent, clinker, final point of delivery, flexigas, fugitive source, ISO, lead verifier, long-term power contract, low Btu gas, low heating value, mobile combustion source, NVTREC, power, process, small refiner, standard cubic foot, thermal host, useful power output, volatile organic compounds, waste-derived fuel, and WREGIS. (§95102)
- Definitions for the following terms were deleted as no longer necessary: accredited verifier, API, delayed coking, source stream, specified wholesale sales, still gas, substitute energy, and verified emissions data report. (§95102)

- Revisions were made to a number of other definitions, including but not limited to definitions of the following terms: adverse verification opinion, annual, AQMD/APCD, associated gas or produced gas, best available data and methods, biomass-derived fuels, butane, carbon dioxide, catalytic cracking, cement kiln dust, coal, coal-derived fuel, cogeneration facility, cogeneration system, coke burn-off, combustion source, conflict of interest, continuous emissions monitoring system, diesel fuel, direct emissions, distributed emissions, electricity generating facility (replacing a definition of "electric generating facility"), emission factor, emissions, entity, ethane, equipment, facility, flare, fluid catalytic cracking unit, fugitive emissions, greenhouse gas, greenhouse gas source, hydrocarbons, kerosene, kiln, liquefied petroleum gas, marketer, material misstatement, mobile combustion emissions (replacing a definition of "mobile combustion"), multi-jurisdictional retail provider (replacing a definition of "multi-jurisdictional utility"), nameplate generating capacity, natural gas, net power generated (replacing a definition of "net generation"), NERC E-tag, nonconformance, null power, operator, operational control, positive verification opinion, process emissions, process vents, pure, reasonable assurance, recycled, renewable energy, retail provider, self-generation facility, source, specified source of power, standard conditions, stationary combustion source, storage tank, sulfur recovery unit, supplemental firing, uncertainty, verification cycle, verification opinion, and verification team, as well as revisions made to various diesel fuel and distillate fuel definitions. (§95102)
- The general reporting requirement was amended to clarify that emissions calculations need to be performed and reported for all six identified greenhouse gases as specified in the sector-specific requirements. (§95103)
- Language was added to require that fuel consumption at all facilities be reported at both the facility level and, when fuel use is separately metered by process unit, at the process unit level. (§95103).
- The cap on emissions from designated *de minimis* sources, to which simplified calculation methods may be applied, was raised from 10,000 to 20,000 metric tonnes of CO_2 equivalent emissions, and other changes were made to the *de minimis* provision. (§95103)
- The required level of accuracy for fuel use measurements was revised to require accuracy to within 5 percent of actual use, a decrease from the 2.5 percent originally required. In addition, documentation and calibration requirements were added, and language in the fuel analytical data and fuel use measurement provisions was otherwise modified. (§95103)
- An additional year, until January 1, 2011, was provided for the optional installation of continuous emissions monitoring systems (CEMS). The option for facilities to report emissions on the basis of fuel-based calculations pending installation of a new CEMS or a CEMS CO_2 monitor was limited to apply only when a new CEMS, and not a CEMS CO_2 monitor, is to be installed. (§95103)
- Language was added to provide a process for obtaining ARB approval of an interim data collection procedure during breakdown of fuel analytical data monitoring equipment. (§95103)

- The reporting schedule was modified and reorganized to more clearly list the operators subject to April 1 and June 1 reporting deadlines. (§95103)
- The verification schedule was revised to specify triennial verification for geothermal generating facilities and to make the initial year for obtaining required verification services, 2010, consistent for all operators. Another revision requires that verification bodies rather than operators submit verification opinions to ARB. (§95103)
- A provision governing reporting requirements for new facilities was modified to clarify that it does not apply when there is a management, ownership or operational change at an existing facility, and to make other clarifying changes. (§95103)
- Refineries and hydrogen plants were added to a provision that allows operators of certain facilities to stop filing annual reports if the facility's emissions drop below designated levels for three consecutive years. (§95103)
- The description of information that all operators must include in annual reports was modified to require the inclusion of operator contact information, the identification of facilities owned or operated by parent companies of the operator, the reporting of emission factors developed using approved facility source testing, and other changes. (§95104)
- A signature requirement was modified to require that when signing an annual report, the operator must attest that the report is true, accurate and complete, and prior language permitting these statements to be based on the signer's "best knowledge and belief" was deleted. (§95104)
- Changes to the document retention provision clarify that emission data are just one of the types of documents that must be retained for five years. In addition, a new provision requiring operators to maintain a log of changes to GHG accounting methods was added to the section on record-keeping requirements, and other changes were made to the record-keeping provisions. (§95105)
- Changes were made to the confidentiality section to clarify that all emissions data is public information, consistent with existing law. (§95106)
- Enforcement provisions were consolidated and revised to, among other things, clarify that penalties for failing to file documents on time with ARB apply to all documents that are required to be submitted, including verification opinions. (§95107)
- Additional documents have been incorporated by reference into the regulation. (§95109)
- Other modifications were made to §§95100-95109.

Cement Plants, §95110

- Revisions were made to the emissions data report requirements to clarify that all the listed information and methodologies are mandatory, to specify the reporting units, and to include other details. Reporting of inputs for efficiency metrics was added.
- A provision was added to clarify that cement plant operators are required to report emissions from any electric generating facilities they operate pursuant to §95111 to the extent the generating facilities are themselves subject to the reporting regulation.
- Options for calculating CO_2 emissions from biomass, municipal solid waste, and waste-derived fuels were added and modified, and various other provisions were modified.

Electric Generating Facilities, Retail Providers, Marketers, §95111

- Provisions regarding the kinds of electricity transactions to be reported by multi-jurisdictional retail providers (those serving customers in more than one state) were modified and added.
- Language was added to clarify that retail providers will report imports for which they are the first deliverer.
- The option to report as an asset owning or asset controlling supplier was broadened to be available to suppliers that sell 50 percent or more renewable energy or that purchase no more than 20 percent of the power they sell from unspecified sources. As part of this change, an additional reporting requirement was included for certain suppliers that make use of this option.
- References to substitute energy were deleted.
- References to the ownership share differential of generating plants owned by retail providers were deleted and the reporting of specified information on out-of-state power transactions related to those plants was made voluntary.
- Eligibility criteria for retail providers to designate electricity from generating facilities as serving native load were modified.
- Classification categories were added for reporting power taken by retail providers from large hydroelectric and nuclear facilities.
- Biomass facilities without specified measurement devices were provided the option of testing fuels for heat value or carbon content in lieu of using default emission factors.
- A methodology to calculate fugitive hydrofluorocarbon (HFC) emissions from single unit service records was specified.
- Other provisions relating to generating facilities, retail providers and marketers were modified.

Cogeneration Facilities, §95112

- An option and associated methods were added to allow simplified reporting by small cogeneration facilities (less than 10MW). The simplified reporting option applies only to self-generation facilities.
- Distributed emissions provisions were modified.
- Identification of facility type and nameplate data for waste heat technology were added to emissions data reports.
- Other modifications were made to cogeneration provisions.

Petroleum Refineries, §95113

- An emission reporting threshold of 25,000 MT CO_2 was added for petroleum refining facilities.
- Clarifications were made to specify reporting of feedstock consumption, as well as emissions from burning low Btu gases and flexigas.
- A provision was added to clarify that refinery operators are required to report emissions from any electric generating facilities they operate pursuant to §95111 to the extent the generating facilities are themselves subject to the reporting regulation.
- Provisions were added to allow operators to measure combustion and process emissions using continuous emission monitoring systems (CEMS). A provision was also added (see §95125) to allow refiners to determine refinery fuel gas composition using in-line continuous emission monitoring systems.
- A calculation method was added for process emissions from catalytic regeneration to cover the full range of emissions resulting from catalyst regeneration.
- Language was added to direct refinery operators to use system specific gas analysis where available to calculate a (volatile organic carbon) VOC to methane (CH_4) conversion factor for the calculation of equipment fugitive emissions, and to use the ARB default value where such information is unavailable.
- A provision was added to various emissions calculation equations to allow molar volume conversion at the standard temperature and pressure values typically used at refineries.
- The section on equipment fugitive emissions was restructured to reflect differences in the Leak Detection and Repair (LDAR) program operational and emission calculation requirements in effect at the various air districts.
- Language was added to provide sampling and calculation methods for both associated gas and low Btu gas. A method was added to section 95113(d) for calculation of emissions resulting from the destruction of low Btu gases by incineration or combustion as a supplemental fuel.
- Other modifications were made to refinery provisions.

Hydrogen Plants, §95114

- A correction was made to the equation for the fuel and feedstock mass balance option.
- A provision was added to clarify that hydrogen plant operators are required to report emissions from any electric generating facilities they operate pursuant to §95111 to the extent the generating facilities are themselves subject to the reporting requirements.
- A provision requiring tracking and reporting of transferred CO_2 was expanded to also require tracking and reporting of transferred CO.
- Other modifications were made to refinery provisions.

General Stationary Combustion Facilities, §95115

- Emission calculation methods were specified for non-common fuels for which emission factors were not available.
- Other modifications were made to general stationary combustion provisions.

Additional Calculation Methods, §95125

- Language was added to specify methods and sampling requirements for determination of the high heat value of solid fuels.
- Test methods were added for biomass-derived, waste-derived, and other fuels. The term "alternative fuels" was changed to "waste-derived fuels."
- A carbon content sampling frequency requirement for refinery fuel gas was added.
- Reduced refinery fuel gas sampling requirements were added for refineries that qualify as "small" under title 13 of the California Code of Regulations.
- Facilities burning biomass were provided the option to use O_2 CEMS data to calculate CO_2 emissions, and requirements for the determination of biomass content in waste-derived fuels were clarified.
- A provision was added to allow operators to use an in-line continuous analyzer for the determination of fuel gas carbon content.
- Language was added to specify a method to convert low heating values (LHV) to high heating values (HHV).
- Other modifications were made to this section.

Verification, §95130 - §95133

- Provisions were added to clarify that the sampling plan must be maintained by the verification body, but need not be included in the verification report.
- Language regarding the accreditation application process was modified.
- A provision regarding lead verifiers' experience working in other reporting programs was clarified.

- Language was added to clarify that verifiers (like operators) are subject to verification deadlines.
- Provisions were added to: limit the circumstances under which a final verification opinion may be changed, allow the Executive Officer to set aside opinions under certain circumstances, and require the cooperation of the verification body in the event of an audit of the services it provided.
- Other modifications were made to the verification provisions.

Appendix A – Emission Factors and Methods

- In Table 3, fuel usage equivalents to CO_2 were added in additional units for natural gas, landfill gas, and petroleum coke.
- Biogas emission factors were corrected to include both CH_4 and pass-through CO_2, and the geothermal emission factor was corrected for the proper units.
- Emission factors for fugitive methane emissions from coal were updated to be more current and region specific.
- A table was added for emission factors for oil/water separators.
- The table for mass balance estimation of SF_6 and HFCs was augmented with a pounds-to-kilograms conversion.
- Other corrections, additions and updates were made to emission factors and other tables.

The preceding list identifies many of the changes made to the regulations published on October 19, 2007, but the list does not identify or summarize all changes made. All changes made to the regulation since October 19, 2007, are shown in underline and strikeout in the modified text made available during the review period from May 15, 2008, to June 5, 2008.

Second Availability of Modified Text

Additional modifications to the regulations originally published October 19, 2007, were made available to the public for comment on June 30, 2008. The changes are summarized below. The section and page numbers shown below for each item refer to the document: "Attachment A: Modified Regulatory Language, including Appendix A," published on June 30, 2008.

- Clarified that the fuel use measurement accuracy requirement applies only to facility equipment used to calculate GHG emissions. (§95103(a)(9), page A-27)
- Corrected typographical errors in two cross-references relating to parent company information requirements. (§95104(a)(8)(C) and (D), page A-33)
- Removed language that would have the unintended effect of requiring electricity marketers and retail providers to report emissions data for power plants they do not operate. (§95111(c) and (d), pages A-56 and A-59)
- Corrected a cross-reference in a power plant biofuels provision to add one calculation method, to remove another inapplicable method, and to clarify that only one of the listed methods will be used. (§95111(c)(7)(B), page A-58)

- Clarified that refinery fuel and feedstock consumption reporting is only required for data used to compute GHG emissions. (§95113(a)(3), page A-69)
- Corrected cross-references relating to use of Continuous Emissions Monitoring Systems (CEMS) at refineries (§95113(a)(1) and 95113(b), pages 69 and 70), and fixed a typographical error in a section notation for catalytic cracking. (§95113(b)(1)(A), page A-70)
- Explained the constant "3.664" in the equation for calculating refineries' flaring emissions, and provided that the carbon fraction of NMHC from district-mandated sampling be used when available. (§95113(d)(2)(A), page A-82)
- Clarified a provision relating to general stationary combustion facilities by cross-referencing another section and deleting potentially ambiguous language. (§95115(a), page A-88)
- Clarified which gases are subject to monthly testing when calculating CO_2 emissions using measured heat content. (§95125(c)(1)(A)2, page A-93 and 94)
- Corrected several references to one term and explained the constant "3.664" in the equation for calculating GHG emissions from heat and carbon content. (§95125(e)(3) and §95125(e)(3)(B), page A-98 and 99)
- Corrected a cross-reference in a calculation method for refineries. (§95125(f)(1)(C), page A-100)
- Fixed a typographical error in a reference to federal law. (§95125(g)(7), page A-102)
- Expanded a subsection heading to more accurately reflect the subsection's application. (§95125(h), page A-102)
- Corrected an error in a requirement for facilities to calculate biomass emissions from waste-derived fuels. (§95125(h)(2), page A-103)
- Revised verification language to eliminate a contradiction as to when verification is first required. (§95130(a)(1), page A-108)
- Revised two values in a table of emission factors for municipal solid waste to be consistent with other protocols and fixed a typographical error in the table's web address. (Table 4, Appendix A, page A-7)
- Revised all values in a table of emission factors for waste-derived fuel to correct a unit conversion error in the original data. (Table 5, Appendix A, page A-8, pages A-11 and A-12)
- Added an emission factor needed for reporting "derived gases" emissions and added a source reference to the table. (Table 6, Appendix A, page A-9)
- Replaced a table of emission factors for on-road mobile sources with updated factors to be consistent with other reporting programs. (Table 8, Appendix A)
- Added a reference document for Gasoline vehicle factors from EPA Climate Leader, Mobile Combustion Guidance (2008) based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2005 (2007)*
- Added reference document for *MSW California Air Resources Board*, California Air Resources Board, 2008.

Additional Modifications
After the close of the second 15-day comment period, the Executive Officer determined that no additional modifications should be made to the regulations, with the exception of the nonsubstantial changes listed below.

Renumbered Articles: As originally proposed, the regulations were to be contained in a new article 1, subchapter 10 created in chapter 1, division 3, title 17, of the California Code of Regulations. The location of the regulations was changed from article 1 in subchapter 10 to a new article 2. The section numbers of the regulations were not changed; the only change was that the regulations were moved from Article 1 to a new article 2. This change was made because ARB wishes to reserve article 1 for an index of California's climate change regulations, which would be developed and adopted in the future.

Punctuation and formatting corrections: Unnecessary, missing or inconsistently applied punctuation marks and text spacing were removed, added or changed.

Change in order of definitions: The location of three definitions ("global warming potential," "high heat value" and "operational control") were changed in the list of definitions in section 95102(a) to place them in correct alphabetical order; the numbering for these and several surrounding definitions were also changed as a result.

Corrected reference to "metric tonnes": A reference in section 95103(e)(1) to "metric tons" was corrected to "metric tonnes" to match the defined term and for consistency with all other references to reporting thresholds.

Typographical error in asphalt formulas: Erroneous references to "MCV" to indicate the molar volume conversion factor in two formulas in section 95113(b)(4) were changed to "MVC," the defined variable.

Addition of units for reporting: In section 95114(b)(2) under the fuel and feedstock mass balance formula for hydrogen plants, the unit of measure for CO_2 was added to make it consistent with other references, as follows with the added language underlined:

CO_2 (metric tonnes/year-) = carbon dioxide (fuel)

Correction in brackets of cross-reference: In section 95125(f)(1)(A), a cross-reference to section "95125(f)(1)(B-D)" was corrected to "95125(f)(1)(B)-(D)."

III.

SUMMARY OF COMMENTS AND AGENCY RESPONSES

The Board received numerous written and oral comments during the 45-day and 15-day comment periods for this regulatory action. A list of commenters is shown below, along with an abbreviation for each commenter, which was assigned by ARB staff to help identify individual comments and responses. Following the list, staff has summarized each comment provided regarding the proposal with an explanation of how the proposed action has been changed to accommodate the comment, or the reasons for making no change.

All comments are labeled in this document to allow identification of the submitter of the comment. In the text that follows, each comment is appended with an abbreviation such as "SPI(5)." As seen in the table below, this corresponds to a comment from a letter from Sierra Pacific Industries. Because comments were received through various mechanisms, we have tagged comments received as shown below.

Key:	# only	Comments that are numbered with a number only are written comments received during the initial 45 day comment period.
	BH#	Comments whose numbers are prefixed with "BH" are written comments provided at the Board hearing on December 6, 2008.
	T#	Comment numbers prefixed with "T" were public testimony provided verbally at the Board hearing on December 6, 2008.
	FF#	Comment numbers prefixed with "FF" were received during the first fifteen day comment period.
	FS#	Comment numbers prefixed with "FS" were received during the second fifteen day comment period.

All public comments received are posted here:
http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm

List of Commenters and Abbreviations

Commenter Abbreviation	Comment Number	Commenter/Testimony
Covanta		Jeffrey L. Hahn, PE, BCEE, QEP
		Director, Environmental
		Covanta Energy Corporation
	1	Written Comments: October 25, 2007
	FF1	Written Comments: May 15, 2008
RPower1		Russ Bennett
		Redding Power
	2	Written Comments: October 29, 2007
RPower2		Russ Bennett
		Redding Power
	3	Written Comments: October 29, 2007
LLNL		David Armstrong
		Lawrence Livermore National Laboratory
	4	Written Comments: November 09, 2007
SPI		Bob Ellery
		Sierra Pacific Industries
	5	Written Comments: November 12, 2007
EE		Bruce Falkenhagen
		Energy Enterprise
	6	Written Comments: November 13, 2007
APC		Bill Buchan
		Altivity Packaging Cogen
	8	Written Comments: November 14, 2007
CCMEC		Gregory Knapp
		Chairman PCA AB32 Task Force representing
		California Cement Manufacturers Environmental
		Coalition CCMEC / PCA
	9	Written Comments: November 19, 2007
	BH1	Written Comments: December 6, 2007

Commenter Abbreviation	Comment Number	Commenter/Testimony
CLFP		Rob Neenan
		Director of Regulatory Affairs
		CA League of Food Processors
	10	Written Comments: November 19, 2007
Sempra		Taylor Miller
		Senior Environmental Counsel
		Sempra Energy
	11	Written Comments: November 20, 2007
	T20	Oral Testimony: December 6, 2007
	FF13	Written Comments: June 5, 2008
	FS1	Written Comments: July 14, 2008
API		Karin Ritter
		Manager
		Regulatory and Scientific Affairs
		American Petroleum Association (API)
	12	Written Comments: November 26, 2007
PGE		John Busterud
		Pacific Gas & Electric Company (PG&E)
	13	Written Comments: November 26, 2007
	T3	Oral Testimony: December 6, 2007
	FF9	Written Comments: June 5, 2008
TSuen		Timothy Suen
	14	Written Comments: November 26, 2007
NRDC		Devra Wang
		Natural Resources Defense Council
	15	Written Comments: November 26, 2007
	T1	Oral Testimony: December 6, 2007
SCE		Cathy Karlstad
		Southern California Edison
	16	Written Comments: November 27, 2007
	FF8	Written Comments: June 5, 2008
PPG		Ray Yee
		Plant Manager
		PPG Industries, Inc.
	17	Written Comments: November 28, 2007

Commenter Abbreviation	Comment Number	Commenter/Testimony
REU		Elizabeth Hadley
		Resource Planner
		Redding Electric Utility (REU)
	18	Written Comments: November 28, 2007
USEPA		Leif Hockstad
		U.S. EPA
	19	Written Comments: November 29, 2007
SJRC		David Campbell
		Environmental Manager
		San Joaquin Refining Company, Inc.
	20	Written Comments: November 29, 2007
CBE		Julia May
		Senior Scientist
		Communities for a Better Environment
	21	Written Comments: November 29, 2007
	T6	Oral Testimony: December 6, 2007
Praxair		Jim Merriam
		Director, Corporate Environmental Services
		Praxair, Inc.
	22	Written Comments: November 29, 2007
	FF5	Written Comments: June 4, 2008
WSPA		Cathy Reheis-Boyd
		Chief Operating Officer and Chief of Staff
		Western States Petroleum Association (WSPA)
	23	Written Comments: November 30, 2007
	T23	Oral Testimony: December 6, 2006
	FF17	Written Comments: June 5, 2008
	FS3	Written Comments: July 15, 2008
Calpine		Barbara McBride
		Director, Environmental, Health and Safety
		Calpine Corporation
	24	Written Comments: November 30, 2007
	FF14	Written Comments: June 5, 2008

Commenter Abbreviation	Comment Number	Commenter/Testimony
CMUA		Bruce McLaughlin Braun & Blaising, P.C. California Municipal Utilities Association
	25	Written Comments: November 30, 2007
	T7	Oral Testimony: December 6, 2007
KERN1		Jerry L. Frost, REA, REM Environmental Coordinator Kern Oil and Refining Company
	26	Written Comments: November 30, 2007
	T4	Oral Comments: December 6, 2007
SWC		Terry Erlewine General Manager State Water Contractors
	27	Written Comments: November 30, 2007
	BH4	Written Comments: December 6, 2007
WAPA		Koji Kawamura Attorney DOE - Western Area Power Administration
	28	Written Comments: December 3, 2007
Raytheon		Monica Tully Raytheon – SAS
	29	Written Comments: December 3, 2007
ECOTEK		Natasha Meskal President Ecotek
	30	Written Comments: December 3, 2007
	FF16	Written Comments: June 5, 2008
NSFISR		John C. Shideler, PhD NSF-ISR GHG Program Manager International Strategic Registrations
	32	Written Comments: December 3, 2007
KERN2		Jerry L. Frost, REA, REM Environmental Coordinator Kern Oil & Refining Company
	33	Written Comments: December 3, 2007

Commenter Abbreviation	Comment Number	Commenter/Testimony
NUMMI		K. Kelly McKenzie General Counsel New United Motor Manufacturing, Inc. (NUMMI)
	34	Written Comments: December 4, 2007
NUMMI2		Tony Fischer NUMMI
	T9	Oral Testimony: December 6, 2007
CPhillips		Daniel Hunter ConocoPhillips
	35	Written Comments: December 4, 2007
NLA		Emily W. Coyner Director, Regulatory Issues National Lime Association
	36	Written Comments: December 4, 2007
DWR		Holly B. Cronin, Senior HEP Utilities Engineer Strategic Power Planning Branch State Water Project Operations Division California Department of Water Resources
	37	Written Comments: December 4, 2007
STI		Anthony Pocengal Solar Turbines Incorporated
	38	Written Comments: December 4, 2007
FCE		Joe Heinzmann FuelCell Energy
	39	Written Comments: December 4, 2007
MWD		Diana Mahmud Metropolitan Water District of Southern California
	40	Written Comments: December 4, 2007
APC		Keith Adams, P.E. Environmental Manager – Tonnage Gases, Equipment and Energy Business Air Products and Chemicals
	41	Written Comments: December 5, 2007
	FS4	Written Comments: July 15, 2008

Commenter Abbreviation	Comment Number	Commenter/Testimony
EPUC/CAC		Energy Producers and Users Coalition and the Cogeneration Association of California Donald Brookhyser Alcantar & Kahl, LLP
	42	Written Comments: December 5, 2007
	FF12	Written Comments: June 5, 2008
SP		Sierra Pacific William W. Westerfield, III Ellison, Schneider & Harris, L.L.P.
	43	Written Comments: December 5, 2007
BACWA		Jim Sandoval Air Issues and Regulations Committee Bay Area Clean Water Agencies
	44	Written Comments: December 5, 2007
MKP		Mike Polyniak MKP Environmental & TRC Operating Company
	45	Written Comments: December 5, 2007
AREM		Alliance for Retail Energy Markets Gregory S. G. Klatt Douglass & Liddell
	46	Written Comments: December 5, 2007
	T16	Oral Testimony: December 6, 2007
AB32IG		Robert Callahan AB 32 Implementation Group
	47	Written Comments: December 5, 2007
ACC		Lorraine Krupa Gershman Director, Regulatory and Technical Affairs American Chemistry Council (ACC)
	48	Written Comments: December 5, 2007
BPA		Don Wolfe Bonneville Power Administration
	49	Written Comments: December 5, 2007

Commenter Abbreviation	Comment Number	Commenter/Testimony
SMUD		Sacramento Municipal Utility District Jane Luckhardt Downey Brand LLP
	50	Written Comments: December 5, 2007
NCPA		Susie Berlin Attorneys for the Northern California Power Agency
	BH2	Written Comments: December 6, 2007
SCE		Eric Little Southern California Edison
	BH3	Written Comments: December 6, 2007
	T13	Oral Testimony: December 6, 2007
BAAQMD		Mark Ross Chairperson of the Board of Directors Bay Area Air Quality Management District
	BH7	Written Comments: December 6, 2007
	T11	Oral Testimony: December 6, 2007
LADWP		H. David Nahai, President Los Angeles Department of Water and Power
	BH6	Written Comments: December 6, 2007
Chev		Mark Nordheim Chevron Corporation
	T2	Oral Testimony: December 6, 2007
SJVAPCD		Tom Jordan San Joaquin Valley Air Pollution Control District
	T5	Oral Testimony: December 6, 2007
CBE2		Jesus Torres Communities for a Better Environment
	T8	Oral Testimony: December 6, 2007
SCAQMD		Barry Wallerstein South Coast Air Quality Management District
	T10	Oral Testimony: December 6, 2007
CAPCOA		Doug Quetin California Air Pollution Control Officers Association
	T12	Oral Testimony: December 6, 2007

Commenter Abbreviation	Comment Number	Commenter/Testimony
WM		Chuck White
		Waste Management
	T14	Oral Testimony: December 6, 2007
MCNC		Anne McQueen
		Mitsubishi and National Cement
	T15	Oral Testimony: December 6, 2007
UCS		Don Anair
		Union of Concerned Scientists
	T17	Oral Testimony: December 6, 2007
ED		Tim O'Connor
		Environmental Defense
	T18	Oral Testimony: December 6, 2007
CCAR		Derek Markolf
		California Climate Action Registry
	T19	Oral testimony: December 6, 2007
Sierra		Darrell Clarke
		Sierra Club
	T21	Oral Testimony: December 6, 2007
ALA		Bonnie Holmes-Gen
		American Lung Association
	T22	Oral Testimony: December 6, 2007
Hagen		David L Hagen
	FF2	Written Comments: May 20, 2008
Beta		Sam Thierry
		Beta Analytic Inc
	FF3	Written Comments: May 29, 2008
Silva		Manuel Silva
	FF4	Written Comments: May 30, 2008
Valero		Matthew Hodges
		Valero Energy Corporation
	FF6	Written Comments: June 5, 2008

Commenter Abbreviation	Comment Number	Commenter/Testimony
Geomatrix		Anne McQueen
		Geomatrix
	FF7	Written Comments: June 5, 2008
BVES		Tracey Drabant
		Bear Valley Electric Service
	FF10	Written Comments: June 5, 2008
LADWP2		Cindy Parsons
		Los Angeles Department of Water and Power
	FF11	Written Comments: June 5, 2008
PER		Marina Robertson
		Pacific Energy Resources, LTD
	FF15	Written Comments: June 5, 2008
ElPaso		Fiji George
		El Paso Corporation
	FS2	Written Comments: July 15, 2008

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45-DAY COMMENTS
AND STAFF RESPONSES

A. Article 2. Mandatory Greenhouse Gas Emissions Reporting

§95101 Applicability

A-1. Include Only "Industrial" Facilities
Comment: Change subsection 95101(b)(8) from "Operators of other facilities…" to "Operators of other industrial facilities…" This would exclude facilities from reporting that exceed the 25,000 tonne emissions threshold based on comfort heating or other non-industrial combustion emissions. [LLNL(4)]

Agency Response: Based on ARB analysis, we consider any source that emits 25,000 metric tons or more of CO_2 from combustion sources to be significant for the purposes of emissions reporting. In estimating and reporting greenhouse gas emissions, it is not relevant if those emissions result from an industrial boiler, or a furnace or boiler used for other sources. Therefore, we have not incorporated the suggested change because it could limit the effectiveness of the reporting program by potentially excluding large emission sources from the reporting requirements.

A-2. Limit Reporting to Facilities Producing Direct Emissions
Comment: Reporting should only be required of facilities that, in the course of doing business, directly emit greenhouse gases. [AB32IG(47)]

Agency Response: The regulation currently reflects this comment. Only those facilities that directly emit greenhouse gas emissions are required to report their emissions.

A-3. Facility Reporting Threshold – 25,000 tonnes CO_2/year
Comment: Retain the 25,000 tonne reporting threshold because a lower threshold would include hundreds more facilities with a minor increase in reported emissions [CLFP(10)]. For consistency, use the same thresholds used in the European Union and Canadian programs [PPG(17)]. Increase the threshold to 100,000 tonnes to be consistent with European Union and proposed Canadian programs [ACC(48)].

Agency Response: The Act required ARB to begin mandatory reporting with the sources or categories of sources that contribute most to statewide GHG emissions. ARB conducted inventory analysis and worked with stakeholders in setting reporting thresholds consistent with these requirements. We found that a threshold of 100,000 metric tonnes CO_2 would not capture many sources of interest for possible reductions, while a threshold of 10,000 metric tonnes CO_2

would capture many more sources (some unnecessarily) but would only increase the portion of the overall inventory captured by 2 percent. ARB selected 25,000 metric tonnes CO_2 as the most appropriate threshold consistent with Act requirements, and considering expected needs for future reductions and industry burden. (Lower thresholds were established for the electricity sector due to Act requirements for that sector in particular.) Emissions at this level require fuel combustion of a magnitude associated with large industrial facilities, e.g., in excess of 12,000 short tons of coal, 2.8 million gallons of gasoline, or 450 million standard cubic feet of natural gas. A threshold of 25,000 tonnes is comparable in size to other reporting programs, including the Regional Greenhouse Gas Initiative, the U.S. Acid Rain Program, and some sectors of the European Union Emissions Trading Scheme.

A-4. Applicability for Small Refineries

Comment: In developing the GHG regulations, ARB should consider the differences in the economies of scale and recognize how a small independent refiner will be disproportionally impacted compared to larger refineries. [KERN2(33)]

Agency Response: To address this concern, the regulation has been modified to allow small refiners as defined in the California Code of Regulations to sample refinery fuel gas HHV and carbon content on a weekly basis, instead of the daily basis required for larger refineries. This revised sampling regime will reduce the number of samples required by small refineries by a factor of seven, and should also reduce associated costs to less than $30,000 annually. The two "small" California refineries represent approximately 2.5% of the total refinery capacity in the State. Thus, a relaxation of the sampling frequency should not cause a significant reduction in our ability to accurately determine GHG emissions from petroleum refining in the State. The fact that each of these refineries has a single refinery fuel gas collection and blending system also suggests that their refinery fuel gas composition is probably much less variable than in larger facilities where there are multiple systems, and therefore better suited to less frequent sampling.

A-5. Reporting Threshold for Refineries

Comment: Provide a threshold of 25,000 MT CO_2/year to exclude very small "refineries" such as asphalt refiners from reporting requirements. [EE(6)]

Agency Response: A 25,000 MT CO_2/year threshold has been added for refineries. It is the intent of the reporting regulation to account for all *major* industrial GHG sources in the State. A threshold of 25,000 MT/year is consistent with that set for hydrogen production facilities and "general stationary combustion" sources while exempting very small refineries.

A-6. Applicability of Cogeneration Reporting Requirements to Industrial Waste Heat Recovery Systems (Bottoming Cycle Cogen)

Comment: Regulation should not require that operators of general stationary combustion cogeneration facilities be subject to cogeneration reporting requirements, as it will discourage manufacturing facilities from installing waste heat recovery systems in the future. Revise the definition of cogeneration facility to exclude new projects for the reuse of waste heat within the facility, as such projects are already economically marginal and would substantially expand an operator's GHG reporting requirements. [PPG(17)]

Agency Response: ARB appreciates the contribution of many waste heat recovery projects to net emissions reduction. General stationary combustion facilities are large sources of emissions, however, and cogeneration plants can be principal sources of emissions at these facilities, particularly when augmented with supplemental firing for purposes of generating electricity. It is especially important to obtain information on emissions from application of this technology where it helps meet electrical load. This provision is consistent with the Act's requirement to account for emissions from all consumed electricity.

Cogeneration requirements do not apply to systems that do not involve electricity generation (see definition of the term "cogeneration system"). Also, an option and associated methods were added to allow simplified reporting by small cogeneration facilities (less than 10MW). The simplified reporting option applies to self-generation facilities that are not within facilities otherwise required to report. Also see responses to comments C-75 and H-28.

A-7. Applicability Threshold for Electricity Generators and Reduced Requirements for Cogeneration Facilities Less than 10 MW

Comment: The substantially lower applicability threshold for cogeneration facilities and electricity generators does not appear justified. AB 32 requires ARB to minimize costs of mitigation. Streamline the regulation for smaller generators. [EPUC/CAC(42)] Increase reporting size from 1 MW or greater to 12 MWs or greater for generating facilities, recognizing the benefits of distributed generation. [FCE(39)]

Agency Response: Based on ARB's analysis of electricity generation and cogeneration facilities in California, the lower threshold for generating facilities is essential to meeting the requirement of AB 32 to "account for greenhouse gas emissions from all electricity consumed." Significant and growing portions of the load are met with smaller generating facilities. ARB needs to be able to track the growth in distributed generation as part of monitoring the results of Act implementation. ARB revised the regulation to reduce the cost burden for small facilities (less than 10 MW), including reduced verification schedules and abbreviated reporting for self-generating units not otherwise required to report.

A-8. Applicability of Reporting Rules to Offshore Oil Facilities.

Comment: Three offshore oil production platforms located approximately nine miles offshore from Huntington Beach, California will not be subject to AB 32 mandatory greenhouse gas emission reporting because the facilities are located in federal waters. The commenter notes that the company already tracks fuel usage under the South Coast Air Quality Management District's RECLAIM program and has data to easily calculate carbon dioxide emissions and other emissions, but does not plan to formally report the carbon emissions under AB 32. [PER(FF15)]

Agency Response: The regulation requires offshore oil or gas facilities in California to report if the facility's CO_2 combustion emissions equal or exceed 25,000 metric tonnes a year, or if they meet other applicability requirements, such as for electricity generation. Offshore facilities are located in California if they are within the state's territorial waters, which extend seaward three nautical (geographical) miles from the coast. Therefore, any offshore source within three nautical miles of shore will be subject to mandatory reporting under this regulation. Facilities located on the outer continental shelf farther than three nautical miles seaward may elect to provide emissions data to ARB, and ARB may track emissions data that these facilities already report to air districts pursuant to federal regulation. Although ARB chose to limit the application of this regulation to sources located in the state, including territorial waters of the state, it may elect in the future to apply AB 32 programs to facilities on the outer continental shelf to the full extent that application of AB 32 is consistent with other laws.

A-9. Geographic Scope of Regulation Unclear

Comment: As written, the proposed regulation is unclear as to whether it is intended to apply to activities that occur entirely outside California, and this ambiguity should be fixed by adding language to section 95101(b) that limits the article's application to statewide greenhouse gas emissions of the listed entities. In particular, the term "statewide greenhouse gas emissions" should be added to section 95101(b) to make clear that it only has application to emissions within the state and those attributed to imported electricity. If the regulation is intended to apply to activities occurring entirely outside California, it is inconsistent with and in direct conflict with the statutory objectives of AB 32. [CMUA(25)]

Agency Response: ARB agrees that as originally proposed, the regulation was not as clear as it could be as to the geographical scope of each of its requirements. For that reason, a set of changes were made to section 95101(b) to clarify the scope. ARB did not believe the commenter's suggested insertion of the term "statewide greenhouse gas emissions" in section 95101(b) would be entirely clear or would accommodate ARB's need, described in response to comment A-10, to receive information about power plants operated or owned by California retail providers outside the state. Instead, ARB modified section 95101(b) to specify that the reporting requirements apply to cement plants, petroleum refineries, hydrogen plants, and other stationary combustion sources that are located in California, and to electricity generating facilities and cogeneration facilities that are either located in

California or operated by a California retail provider. No modifications were made to the applicability of the provisions for retail providers or marketers because the transactions that each of these is required to report are more specifically delineated in section 95111(b).

A-10. No Authority to Regulate Out-of-State Electricity Transactions
Comment: AB 32 does not authorize ARB to exercise jurisdiction over the reporting of emissions that are not statewide greenhouse gas emissions. ARB's statutory authority is limited to "statewide greenhouse gas emissions" as that term is defined in AB 32 and does not include emissions from electricity generated out-of-state that is not delivered to and consumed within California. The reporting regulations may only require entities to report emissions attributable to the amount of electricity actually delivered to and consumed in California. Emissions from electricity generated outside California that is not actually delivered to and consumed in California are not statewide greenhouse gas emissions and cannot be regulated by ARB.

Successive sections in AB 32 must be interpreted to apply only to "statewide greenhouse gas emissions" and ARB has not been authorized by AB 32 to implement regulations for any greenhouse gas emissions not fitting within the definition. The successive sections in AB 32 that are geographically limited by the definition of statewide greenhouse gas emissions includes the sections relating to: the 2020 goal for emissions limits (38505(n) and 38550), emissions reporting (38530(a)-(b)), early action regulations (38560.5(c)), emission limits and reduction measures (38562(a)-(b) and (d)), and monitoring and enforcement programs (38580(a)-(b)(1)). [CMUA(25), CMUA(T7)]

Agency Response: The comment is relevant to this regulation to the extent it addresses ARB's authority to adopt GHG reporting regulations that require the reporting of emissions data and transactions occurring outside California, and provisions to enforce those requirements. Provisions relating to other AB 32 provisions such as emissions limits and emissions reduction measures are not relevant to this regulation and are not discussed in this response.

The regulation as originally proposed required the reporting of emissions data and electricity transactions beyond the state's borders in two situations. First, it required a California retail provider (defined to include various types of utilities) to report specified information about and GHG emissions from all electricity generating plants and all cogeneration facilities that the retail provider operates, regardless of location. (See sections 95101(b)(4), 95101(b)(7); 95111(a), 95111(b)(3)(A), and 95112(a) in final regulation order.) This requirement was retained. Second, the regulation as originally proposed required California retail providers to report ownership information about all generating plants they owned, regardless of location; to report information about wholesale sales of electricity from coal-fired plants owned by retail providers to buyers outside California; to report reductions in power generated from the same coal plants as a result of reduced demand from the retail provider's customers; and to calculate for each of these plants an “ownership share differential” and “adjusted ownership share differential” to identify differences between the retail provider’s ownership share of a power plant and the electricity it received from the plant. These latter owner-based provisions were designed to provide ARB with information to assess whether California utilities are meeting GHG reduction requirements by buying and importing electricity from existing “clean” power plants in other states to replace electricity they formerly had imported from high-emission plants they own outside California.

ARB revised the reporting requirements for power plants owned by retail providers to make the reporting of wholesale sales to out-of-state buyers and the reporting of reduction in generation from retail provider-owned coal plants voluntary rather than mandatory. These revisions also removed the requirement for calculation of the ownership share differential and adjusted ownership share differential, and equations for those calculations. (See section 95111(b)(3)(Q)-(R) of the May 15, 2008 modified text.) As revised, the regulation allows companies to voluntarily submit wholesale sales and reduced output information if they want ARB to have it for possible consideration in a future emissions-control effort. Retail providers are still required to report certain basic information about any plant they own, including those outside the state. This information includes facility name and identification numbers, percent ownership share of the facility and generating unit, and net power generated. (See section 95111(b)(3)(Q).)

ARB does not agree that it lacks authority under AB 32 to collect information relating to these out-of-state operations and transactions. The commenter asserts that the statute’s definition of “statewide greenhouse gas emissions” controls the scope of the program to the exclusion of all other provisions of the law. Granted, AB 32 is focused on the calculation, monitoring and control of “statewide greenhouse gas emissions,” which includes GHG emissions generated within the state as well as those attributable to the generation and transmission of electricity that is imported into and consumed in California. But the statute also contains clear standards for the GHG emissions program that require ARB to ensure, among other things, that reductions in statewide greenhouse gas emissions are “real, permanent, quantifiable, verifiable, and enforceable ....” (Health & Safety Code section 38562(d)(1).) That requirement applies not only to reductions in emissions from electricity generation within the state, but from emissions outside the state linked to electricity generated elsewhere and consumed in California. In addition, ARB must minimize “leakage,” which is defined as a reduction in emissions in California that is offset by an increase in emissions outside the state. (Health & Safety Code sections 38562(b)(8), 38505(j).) The California Energy Commission and the California Public Utilities Commission, two state agencies with expertise in the electricity market, explained in their joint recommendation to ARB that GHG reductions for the electricity sector could prove to be largely meaningless paper reductions if California retail providers engaged in the practice of “contract shuffling,” in which electricity imported from a retail provider's coal-powered plant to meet California demand would be sold to buyers outside the state and replaced with imported electricity from existing cleaner power plants. Such a practice could give the retail provider a large credit for reduced GHG emissions without resulting in any actual reduction at the end of the day. If a market-based control program is adopted in the future for the electricity sector, this sort of paper reduction could provide an economic windfall for certain parties, again without any real reductions in GHG emissions by the California utility. This outcome would be counter to both the intent of AB 32 and its express provisions requiring that reductions be real, permanent, quantifiable, verifiable, and enforceable. So while AB 32 requires ARB to focus on the monitoring, control and reduction of statewide greenhouse gas emissions as defined, it is necessary to collect information relating to electricity generation and sales by California utilities that will be needed to ensure that reported reductions in statewide greenhouse gas emissions are real and that other statutory requirements of AB 32 are met. In addition to the provisions of AB 32, ARB is authorized to take such actions by Health and Safety Code section 39600, which states: "The state board shall do such acts as may be necessary for the proper execution of the powers and duties granted to, and imposed upon, the state board by this division and by any other provision of law."

It also bears emphasizing that this regulation only addresses mandatory reporting, with certain optional components including the one relating to out-of-state wholesale electricity sales from generating plants owned by California retail providers. The type of controls that will be implemented to reduce GHG emissions will be decided in future regulations that ARB is required to adopt by January 1, 2011 to become effective January 1, 2012. On the issues addressed in this comment, this regulation merely: 1) requires California retail providers to report operating and emissions information about power plants that they operate, regardless of location, and 2) provides California retail providers the means to voluntarily report information about wholesale electricity sales to out-of-state buyers and information about reductions in generation output, in both cases from power plants that they own, regardless of location. This regulation imposes no procedural or substantive controls on any out-of-state operations or transactions subject to the reporting provisions, and therefore does not "regulate" these activities in the normal sense of that word.

A-11. Exempt Boilers from Reporting

Comment: Exempt backup boilers from reporting, similar to what has been provided for backup or emergency generators. [CLFP(10)]

Agency Response: We are not able to provide the requested exemption. The exemption for backup or emergency generators is provided because these pieces of equipment are under air district permits and have legally enforceable limitations on their usage. Similar permitting or enforcement mechanisms are not in place for backup boilers. Our concern is that an exemption for all backup boilers could exclude significant levels of emissions from reporting. Note, however, that reporting does not apply to devices that meet the definition of "portable equipment," which could potentially include equipment brought to the site for temporary use in unforeseen emergencies.

A-12. Exclude Comfort Heating from Reporting
Comment: Change subsection 95101(c) to add a new item: (5) Sources that are solely used for comfort heating. This would prevent facilities from being brought into the reporting program due to these emission sources. It would also provide consistency with the staff report which states that "… only those GHG sources specified within the proposed regulation would be reported, while unspecified sources such as residential heating and cooling would not be included." [LLNL(4)]

Agency Response: To maintain a level playing field among general stationary combustion sources, any facility that emits 25,000 metric tonnes or more of CO_2 from combustion sources is subject to reporting unless it falls within one of several exempt categories in section 95101(c). This includes emissions from comfort heating at industrial facilities. At some smaller facilities such fuel use may not be separately metered and thus may be difficult to exclude. At larger facilities comfort heating emissions might qualify for treatment as *de minimis* consistent with the regulation. The cited statement in the Staff Report refers to non-commercial residential heating and cooling.

A-13. Exemption for Schools and Hospitals
Comment: Why do schools and hospitals have any exemption? The legislature didn't allow it. [EE(6)]

Agency Response: In response to the Act's direction to begin with the state's largest GHG sources, the regulation's primary focus is to require reporting from large industrial sources. Hospitals and schools may in some cases operate facilities that marginally exceed regulation reporting thresholds (particularly if they have large boilers on site to provide comfort services), but such facilities represent a very small proportion of GHG emissions and ARB determined that, given the limited emissions from this sector, it was not necessary to include hospitals and schools in the regulation at this time. If ARB decides these facilities should be included in an emissions control program, this regulation may be amended to require reporting from them.

A-14. State Regulation of Western Area Power Administration, Department of Energy
Comment: Section 95101 (b)(5) of the proposed regulation states that GHG reporting requirements will be applicable to "retail providers" of electric service as defined in section 95102(a). Section 95102(a) defines retail providers as: an operator that is any electric corporation as defined in Public Utilities Code Section 218, electric service provider as defined in Public Utilities Code 218.3, public (sic) owned electric utility as defined in Public Resources Code Section 9604, community choice aggregator as defined in Public Utilities Code

Section 331.1, the Western Area Power Administration, or the California Department of Water Resources.

The Western Area Power Administration (Western) is a Federal agency. While Western respects the state's initiative to implement GHG regulations, Western is bound by federal laws and regulations. The Supremacy Clause of the U.S. Constitution does not allow a state to directly regulate the federal government without its consent. Western is unaware of any waivers of sovereign immunity relating to GHG. In the past, Western has worked with other state agencies, such as the California Energy Commission, to provide information the state needs. In the event ARB would like to obtain information from Western, Western is willing to evaluate the request and will work with ARB to provide certain information. However, Western cannot consent to direct state regulation without a waiver of sovereign immunity. [WAPA(28)]

Agency Response: Section 118(a) of the federal Clean Air Act includes a broad waiver of sovereign immunity by Congress. The most relevant part of the statute states: Each department, agency, and instrumentality of the executive, legislative, and judicial branches of the Federal Government (1) having jurisdiction over any property or facility, or (2) engaged in any activity resulting, or which may result, in the discharge of air pollutants, and each officer, agent, or employee thereof, shall be subject to, and comply with, all Federal, State, interstate, and local requirements, administrative authority, and process and sanctions respecting the control and abatement of air pollution in the same manner, and to the same extent as any nongovernmental entity. The preceding sentence shall apply (A) to any requirement whether substantive or procedural (*including any recordkeeping or reporting requirement*, any requirement respecting permits and any other requirement whatsoever), (B) to any requirement to pay a fee or charge imposed by any State or local agency to defray the costs of its air pollution regulatory program, (C) to the exercise of any Federal, State, or local administrative authority, and (D) to any process and sanction, whether enforced in Federal, State, or local courts, or in any other manner. This subsection shall apply notwithstanding any immunity of such agencies, officers, agents, or employees under any law or rule of law...

Clean Air Act section 118(a); 42 USC section 7418(a) [emphasis added]. Greenhouse gases are an air pollutant under the Clean Air Act (*see Massachusetts et al. v. Environmental Protection Agency et al.*, 127 S.Ct. 1438, 1460) and this regulation clearly falls under section 118's waiver of sovereign immunity. As such, the Supremacy Clause of the U.S. Constitution does not prohibit application of this regulation to federal agencies, and the Western Area Power Administration must comply with all applicable requirements of the regulation.

A-15. Revisions Needed After Electricity Point of Regulation is Determined
Comment: ARB should revisit the regulation after the point of regulation has been determined for the electricity sector and remove any duplicate reporting requirements [SCE(16), SCE(BH3), LADWP(BH6), SCE(T13)]

Agency Response: ARB agrees. When ARB selects a point of regulation and fully defines the form of future emission reduction regulations for the electricity sector and for other sectors, it will be important to remove requirements that are no longer needed as well as to add requirements that may be needed to implement future regulations.

A-16. Add Additional Reporting Requirements in Future Regulation Updates
Comment: Over the coming year, recommend that ARB adopt regulations that would require reporting of emissions from at least the following sources: natural gas customers not covered by the 25,000 ton per year stationary source reporting requirement; landfills; fugitive emissions from oil and gas exploration, transmission, and distribution; large stationary sources below the 25,000 ton per year threshold; examine if the reporting mechanisms for the transportation sector are adequate to support the Low Carbon Fuel Standard and full lifecycle accounting. [NRDC(15)] In future updates consider reducing reporting threshold to 10,000 tonnes, include landfill fugitive emissions, natural gas providers, oil and gas extraction facility fugitives, and transportation sector emissions. [ED(T18)]

Agency Response: ARB will evaluate the need to include additional emission sources in future regulation updates. We are aware that the regulation does not address process and fugitive emissions from oil and gas production sources, and are currently working with other states, the California Climate Action Registry, and The Climate Registry on protocols for oil and gas exploration, production, transmission, and distribution to support eventual regulation development. In addition, work is ongoing in the landfill sector to develop estimates for the sector as part of ARB's GHG Early Action efforts. We will work with stakeholders to evaluate the need to incorporate additional reporting requirements, such as modifying reporting thresholds and transportation sector reporting. The current regulation effectively captures the key sectors needed to address the Act's requirement to begin "with the sources or categories of sources that contribute the most to statewide emissions."

A-17. Not Including Transportation Sector Limits Regulatory Options
Comment: Failure to include GHG reporting for the transportation sector in the reporting regulations will cause a problem when preparing the scoping plan for achieving required GHG reductions. The lack of reporting by the transportation sector will limit the opportunity to regulate the sector and place additional pressures on the industrial sector. [MCNC(T15)]

Agency Response: The ARB has comprehensive mechanisms to effectively estimate and evaluate transportation-related GHG emissions on a statewide and localized basis. This has proven sufficient for supporting scoping plan needs, and the draft ARB scoping plan includes aggressive emissions reductions for mobile sources. For those facilities wishing to report their transportation-related emissions, the regulation provides methods for estimating these emissions and ARB's reporting tool will accept submittal of these emissions. ARB will continue to evaluate the need and potential benefits of reporting transportation-related emissions, such as from vehicle fleets, as regulatory needs for such information arise.

A-18. Base Year

Comment: The proposed regulation is silent on how far back in time a facility may go in defining its 'base year' for emissions reporting. This item should be considered carefully in the context of AB32 as a whole and with particular regard to how future GHG emissions allocations may be distributed. Though reasonable boundary limits should be established, a 'one size fits all' approach may prevent operators from demonstrating emissions reductions realized in previous years. We recommend CARB consider this issue for further discussion at the upcoming meetings. [STI(38)]

Agency Response: Defining a base year is important for some types of emission reduction measures, and we agree this question should be carefully considered in that context. The mandatory reporting regulation does not contain a base year requirement because we do not want to presume how a base year will be defined for emission reduction purposes. That issue will be addressed as needed in subsequent emissions control regulations.

A-19. Add Language for Voluntary Reporting

Comment: The regulation does not specify how sources exempt from reporting could voluntarily opt-in to the reporting program. Consider adding language to clarify how facilities could voluntarily report their emissions. [STI(38)]

Agency Response: Voluntary reporting need not be addressed through a regulation, we expect to accommodate voluntary reporting through the reporting tool under development. Interested facilities will need to contact ARB for an identification number.

A-20. Administrative Procedure Act Standards Not Met

Comment: The regulation lacks necessity, authority, consistency, and clarity when it comes to the proposal to regulate, monitor, or measure electricity transactions occurring entirely outside California. [CMUA(25)]

Agency Response: This comment essentially builds on the other comments submitted by the California Municipal Utilities Association to say that because ARB lacks authority to regulate or require information about out-of-state electricity transactions, and because the regulation is unclear as to whether it is intended to apply to out-of-state transactions, the regulation fails to meet several of the legal standards in the Administrative Procedure Act. The regulation's provisions relating to certain out-of-state facilities and electricity transactions are consistent with AB 32 and are a proper exercise of ARB's delegated authority for the reasons discussed in response to comment A-10. This data must be received if ARB is to have the information it will need to ensure that AB 32's standards for future GHG emissions control measures are achieved, as discussed in response to comment A-10.

The California Energy Commission and Public Utilities Commission, two state agencies with expertise in the area of electricity regulation, agreed with this position in their joint recommendation to ARB. Given these facts, it is clear that: 1) ARB has authority to include these provisions in the regulation, 2) these regulations in general and provisions relating to out-of-state transactions and facilities in particular are necessary to accomplish AB 32's purpose, and 3) ARB's collection of certain information about out-of-state transactions and generating facilities is within authority granted by AB 32 and other existing law. Finally, as described in response to comment A-9, ARB modified section 95101(b) to more specifically describe the geographical application of the regulation; these revisions eliminate the ambiguity identified by the commenter as to what reporting requirements are intended to apply outside California, and the modified regulation meets the standard for clarity.

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

§95102 Definitions

B-1. Update the Perfluorocarbon Definition
Comment: Page A-15 of Staff Report. The word "containing" should be deleted from the definition of "Perfluorocarbons". [USEPA(19)]

Agency Response: The change has been made.

B-2. Combustion Source Definition Too Narrow
Comment: Section 95102(A)(47). Expand the definition for combustion sources so that "combustion source" means a stationary fuel fired internal combustion engine, turbine or any external combustion device such as boiler, heater, dryer, furnace, flare, etc. [ECOTEK(30)]

Agency Response: We have modified the definition to reflect this comment. Instead of attempting to enumerate all possible sources, we have instead expanded the definition to include all sources of emissions resulting from combustion. "Combustion emissions" is also defined.

B-3. Proposed Definitions for Alternative Fuels

Comment: Two additional definitions are suggested for alternative fuels in cement kiln systems (both the kiln and pre-heater/pre-calciner tower): Alternative Fuel – A material used to replace traditional fuels such as coal, petroleum coke, virgin (unused) oils, and natural gas in a cement kiln system. Liquid Alternative Fuel – An alternative fuel that is a liquid at standard conditions. [CCMEC(BH1)]

Agency Response: The term "alternative fuel" has been replaced in the regulation with the term "waste-derived fuel," which provides more specificity. A definition for "waste-derived fuel" has been added, which should address the commenter's desire for clarity. The definition is not inconsistent with the commenter's suggestions. We have not added a definition for "liquid waste-derived fuel" but believe this will be self-evident for the waste-derived fuels listed in Table 5 of Appendix A.

B-4. Specification of Standard Conditions

Comment: Request the flexibility to calculate emissions using "industry standard" temperature and pressure conditions of 60°F and 1 atmosphere. [API(12), WSPA(23)]

Agency Response: Provisions have been included in the regulation to allow refiners to calculate GHG emissions at these conditions. In each instance where the regulation required a molar volume conversion factor, operators were given a choice of 20°C or 60°F as requested. Regulation sections affected are 95113(b)(3), (4), and (5), 95113(d)(3), 95125(d)(3), and 95125(e)(3).

B-5. Modify Definitions to Improve Clarity

Comment: Request clarification and/or wording changes for twelve definitions. Proposed clarifications/amendments are found in WSPA comments Attachment A. Suggest addition of three definitions: "low Btu gas," "vent gas," and "volatile organic compounds." [WSPA(23)]

Agency Response: Several of the definitions cited have been modified to provide clarification. Definitions for "low Btu gas" and "volatile organic compounds" have been added". Specific actions/responses concerning the following definitions were as follows: AQMD/APCD – this definition was modified as suggested for clarity and this change in no way affects regulation interpretation; Associated gas – the synonym "produced gas" was added, the remaining text was changed as per the commenter's suggestion, and superfluous information was deleted; Coke (petroleum) – this definition was not modified as the commenter suggested because explanatory information included in the current definition is helpful for providing context; Petroleum coke – this definition was not modified because it is important to include information regarding the origin of the petroleum coke; Coke burn-off – this definition was not modified because the inclusion of the federal regulation (EPA 40CFR 63 Subpart UUU) governing this process was not necessary or warranted, and inclusion of a federal regulation might introduce confusion and perhaps a set of dual definitions which might be in conflict; Diesel fuel – this definition was modified as suggested because the test recommended for deletion was not relevant; Facility – this definition was not modified because the suggested additions would unduly restrict the definition; Flare – this definition was modified as suggested because the additional information clarifies the definition; Hydrocarbons – this definition was modified as suggested and test was deleted that did not enhance the definition; Mobile combustion – this definition was not modified because the current wording provides sufficient information; Sulfur recovery unit – this definition was modified as suggested because the suggested edits provided useful clarification. None of the definition changes discussed above affects the interpretation or application of the regulation.

B-6. Definition of "Operational control" and Reporting Responsibility

Comment: Request that the reporting obligation not default to the party holding the permit to operate from the local air pollution authority where there is an operating entity, able and willing to accept responsibility as the reporting entity, and has business confidential information that would be required to be shared with another entity, typically a customer or supplier. If reporting is transferred to non-operating entity, the operating entity will not be able to make a claim of confidentiality under the California Public Records Act. [APC(41)]

Agency Response: It is important that the GHG reporting regulation assign reporting responsibility to the party best able to coordinate the quantification of GHG emissions. Operational control is the most effective manner to insure that the mandatory reporting objectives of AB 32 are met and to ensure completeness and accountability. ARB acknowledges that complex contractual arrangements are sometimes used between businesses. In the unusual situation in which the entity in "operational control" is not readily apparent, we will work with reporters to identify the most logical reporting party, consistent with the regulation, to ensure complete reporting. Reporting responsibilities will never be transferred to an entity that does not have operational control over the facility. An entity's status as a permit holder is considered only when there is more than one operator for a facility and one of the operators holds a permit

B-7. Clarification of Cogeneration Definitions

Comment: Our facility has a steam turbine that is supplied steam from two boilers and from a Heat Recovery Steam Generator (HRSG) that is on the exhaust of one of our gas turbine/generators. It does not make sense to apply section 95112 to the boilers and turbine/generators because section 95112 requires emissions to be distributed between thermal energy production and electrical production. The thermal energy production from the HRSG and boilers are used to generate electricity. Could section 95111(a)(4) and the related definitions for "cogeneration system" and "cogeneration facility" be clarified so that they do not apply to our facility? [RPower2(3)]

Agency Response: Section 95112 applies to cogeneration facilities that sell or distribute electricity energy and thermal energy for separate purposes. Since all of the energy used in this example is routed to generate electricity, the operator will report information under section 95111 and not under section 95112. ARB revised the definition of cogeneration facility and cogeneration system to clarify the reporting obligation.

B-8. Definition for NERC E-tag

Comment: PG&E suggests the following changes to a definition for accuracy: 95102 (a)(115) "NERC E-tag" means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow ~~within~~, between or across control areas ~~electric utility company territories~~. [PGE(13)]

Agency Response: ARB accepts this recommendation and has revised the definition.

B-9. Definitions for Pacific Northwest and Southwest Regions

Comment: ARB should revisit its definitions of the Pacific Northwest and Southwest regions. The definitions omit Wyoming, Alberta, and Mexico, all of which are in the WECC and electrically interconnected to California. [SCE(16)]

Agency Response: The CPUC and the CEC have advised ARB that little power is delivered from these additional locations and ARB believes that including them in the definitions now would erroneously skew the default emissions factors. If new transmission lines are built to deliver more power from these areas it may be necessary to add these regions in the future.

B-10. DWR not a Retail Provider

Comment: ARB defines DWR as a "retail provider", which is an incorrect statement. DWR recommends that the ARB modify the definitions in section 95102 to delete "the Western Area Power Administration and the California Department of Water Resources" [DWR(37)]

Agency Response: ARB has deleted DWR from the definition for retail provider, though it is otherwise subject to reporting. Since the Western Area Power Administration does provide retail power to some California residents, it was not deleted. See response to comment A-14 for further discussion of the Western Area Power Administration's status in this regulation.

B-11. Definition for Retail Provider

Comment: Notably absent from ARB's proposed regulatory definition is the requirement that a "retail provider" actually function as an entity providing electric service to retail customers which is misleading. Therefore we recommend use of the statutory language or definition from the Joint Recommendations. [MWD(40)]

Agency Response: ARB has added the phrase "an entity that provides electricity to retail end users in California" to the definition for retail provider. Therefore, if MWD does not sell retail electricity it will not report as a retail provider. MWD would report as a marketer for wholesale power that it imports or exports.

B-12. Use the Term "Wholesale Entities"

Comment: Recommend that ARB define wholesale entities and include this term in the definition for wholesale sales as well as throughout the proposed regulation as appropriate when referring to DWR. [DWR(37)]

Agency Response: Staff does not agree that the term "wholesale entities" is needed in the regulation. Introducing this terminology would impact entities that are not retail providers but do buy or sell wholesale power inside California. There is no need for this type of wholesale entity to report to ARB because ARB will collect comprehensive information on greenhouse gas emissions and power transactions from retail providers, marketers, and operators of electric power generating facilities. Thus, it was never ARB's intention to require all wholesale entities to report but rather to specifically require that DWR report.

To address DWR's issue and uniqueness, ARB removed DWR from the definition of retail provider and provided a paragraph in the regulation that specifically addresses DWR reporting requirements. Although DWR is required to report applicable information pertinent to retail providers, the subset of information applicable to DWR is the same as that required of asset owning/controlling suppliers.

Because DWR acts as a marketer when importing power into California, it would have been required to report to ARB in any event; however, by reporting the additional information required of asset owning/controlling suppliers, ARB is able to develop a supplier specific emission factor for DWR. This enables ARB to address the issue raised by entities that purchase wholesale power from DWR. They were concerned that the emissions associated with their purchases would be determined using a default emission factor. Since DWR produces hydro-electric power, entities stated the inaccuracy of this approach. Instead, ARB will be able to determine emissions associated with DWR transactions using a DWR supplier specific emission factor.

ARB also decided it would be valuable to collect information on the power used by DWR because DWR is one of the most significant users of electric power in the state.

B-13. Edit to Verification Opinion Definition

Comment: The term *checklist items* in the definition of "verification opinion" needs clarification. [WSPA(23)]

Agency Response: The reference to the "checklist items" has been removed. ARB determined it was not necessary to require completion of checklist items so decided to delete the reference rather than identify what items were to be included in the checklist.

B-14. Edit to Verified Emissions Data Report Definition
Comment: The definition of a "verified emissions data report" needs clarification. [WSPA(23)]

Agency Response: This definition has been deleted. For greater clarity the regulation uses the term "positive verification opinion."

B-15. Edits to Verification Team/Body Definitions
Comment: Definitions of "verification team" and "verification body" need to be re-written to avoid confusion of responsibilities. [WSPA(23)]

Agency Response: ARB agrees with the commenter's recommended change to "verification body" and has revised the definition accordingly. The definition of "verification team" has been slightly revised, but ARB did not feel that the more significant changes recommended for this definition were called for. The respective responsibilities of verification bodies and verification teams are specified in the regulation in section 95102. A reporting facility or entity contracts with a verification body for verification services. The body assembles a verification team for that project. The verification team must include a lead verifier who is registered as an accredited lead verifier for the parent verification body. The body may assemble many verification teams to provide verification services to address the needs of its various clients.

B-16. Use of the Term "Accredited"
Comment: The term "accredited verifier" should be reconsidered. In international practice individuals are certified, while accreditation is reserved for bodies. [NSFISR(32)]

Agency Response: ARB is familiar with accreditation of individuals in other instances. Private associations such as the American National Standards Institute also accredit individuals, for example. ARB did not want to use the term "certified" to avoid any confusion with the term as used by the California Climate Action Registry, or as used in reference to the operator certifying an emissions data report.

B-17. Update to Adverse Verification Opinion Definition
Comment: Adverse verification opinion. This is a good definition, except for the apparent linkage between the first four lines and the last two lines. A verification body can issue an adverse verification opinion while having completed all verification services. Admittedly, this is rare. However, if the definition continues to include the last two lines after the words "the regulation," it appears to imply

that no verification body can complete its verification services and issue an "adverse verification opinion." I doubt that CARB intends this meaning. From a technical perspective, we believe the definition should end with the words in line 5 "the regulation." [[NSFISR(32)]

Agency Response: ARB agrees and has made a change that resolves the issue. An adverse verification opinion should only be a qualifier on the quality of the emissions data report and not linked to the attestation that a verification body has completed all verification services. The verification body will have a separate opportunity to certify they have completed verification services as required by the regulation as specified in section 95132(c)(2)(C).

B-18. Edit to Verification Opinion Definition

Comment: Definition 188, "Verification opinion." Having defined "verification body" at definition 186, we suggest that the term "verification firm" be replaced in this definition with "verification body." This change will ensure consistency with ISO 14065:2007, "Greenhouse gases – Requirements for validation and verification bodies for use in accreditation and other forms of recognition. [NSFISR(32)]

Agency Response: ARB agrees and has removed the term "verification body" from this definition.

B-19. Edit to Verified Emissions Data Report Definition

Comment: Definition 191, "Verified emissions data report." To ensure consistency with ISO 14065 and your definition 186, please consider changing "third-party verifier" in the second line to "third-party verification body". The distinction between "verifier" and "verification body" is important, because 95131 (c)(1) and ISO 14065 require that a "greenhouse gas statement" (i.e. "verification opinion" – see definition 188) drafted by the verification team (definition 190) be independently reviewed by a competent person within the verification body. [NSFISR(32)]

Agency Response: ARB agrees that a verification body and not a verifier is responsible for a verification opinion, which reflected in section 95132(c)(1). The term "verified emissions data report" was deleted from the definitions in section 95102 because it was not used in the regulation.

§95103 General Greenhouse Gas Reporting Requirements

B-20. Accuracy of Facility and Unit Level Data

Comment: The facility should designate which data (unit level or facility level) is the most accurate and should be used by ARB for calculations and compliance. [LADWP(BH6)]

Agency Response: The regulation requires that meters used to develop GHG emissions data reports meet specified accuracy requirements. Because unit level data will not be rolled up to match facility level data unless stipulated by the reporting entity, the option to treat unit level and facility level data differently is preserved in the reporting tool. Methods for determining which data are more accurate, whether such a determination is needed, or how compliance will be determined, are all questions to be addressed during the development of future emission reduction control regulations such as a trading scheme.

B-21. Differentiate Fossil Fuel Emissions and Biomass-Derived Emissions
Comment: When reporting emissions, it is important to differentiate between emissions due to fossil fuel combustion and biomass-derived emissions. [BACWA(44), WM(T14)] Treating them the same runs counter to the Governor's Bioenergy Action Plan and runs counter to the low carbon fuel standards. [WM(T14)]

Agency Response: ARB agrees that it is important to distinguish between emissions produced from fossil fuel and biomass-derived fuel combustion, and has added language to section 95103(a)(3) of the regulation that addresses the comment. The regulation requires that emissions associated with combusting biomass and biomass-derived fuels be identified and reported separately from emissions associated with combusting fossil fuels. We are committed to ensuring that our reporting requirements, reporting tools, and data management systems clearly account for and distinguish between emissions from different fuel types, including biomass.

B-22. Reporting of PFCs in Electrical Transformers
Comment: The Staff Report states that PFC (perfluorocarbons) are not included for reporting because there is no significant use of PFCs in the sectors affected by the regulation. Though believed to be much smaller than SF6 emissions, PFCs are sometimes used in electrical transformers. PFC emissions have not been quantified in the U.S. [USEPA(19)]

Agency Response: Because our focus under AB 32 is to begin with the largest sources, and due to the lack of accepted methods for estimating PFCs from transformers, the current regulation does not include a PFC reporting requirement. ARB has initiated a research contract to more fully understand the sources and levels of these emissions. Based on these results and other analysis, reporting of PFCs could be included in future revisions to the regulation if warranted.

B-23. Provide Phase-In Period for Reporting
Comment: Support proposed "phase-in" period to allow firms adequate time to understand and comply with the regulation (section 95103(a)(1)). [CLFP(10), APC(41)]

Agency Response: For 2009 emissions data reports, the regulation permits operators to use best available data and methods to estimate emissions for 2008. In addition, the 2009 data submittal is not subject to verification except at the option of the operator. These provisions are intended to provide operators time to prepare for full compliance with the regulation's requirements and in ARB's view establishes a sufficient phase-in period. The subsequent 2010 data submittal must meet the regulation's emission estimation specifications, and other requirements including verification.

B-24. Allow Phase-In Period to Choose Between CEMS and Fuel-Based Approach
Comment: ARB should consider the option of treating the first year of reporting, for 2008, as a true phase-in period where companies could use information gathered from that year to choose which method of reporting, fuel or CEMS based, is better suited for their operation going forward, where applicable. [Sempra(11)]

Agency Response: The regulation allows an operator to alter methodologies between the 2009 and 2010 emissions data reports. The operator has discretion to choose either a CEMS or fuel-based approach as "best available" in 2009, allowing time to address data collection or installation issues that serve the other method. Beginning with the 2010 emissions data report, only one method can be used going forward. The exception would be for facilities installing new CEMS equipment per section 95103(a)(11); in such cases operators have two additional years to install and operate the equipment before incorporating CEMS data into the 2012 emissions data report. The regulation therefore already provides the flexibility urged by the commenter.

B-25. Add Additional Efficiency Metrics in Future Regulation Updates
Comment: For reporting, recommend that efficiency metrics be developed wherever feasible. [NRDC(15)]

Agency Response: The current regulation incorporates specific efficiency metrics (emissions per unit of output) for the cement sector, and efficiency metrics can be derived from other reported data. We will evaluate the need for additional efficiency metrics in future updates to the regulation, particularly where they would serve regulatory strategies under development.

B-26. Reporting Indirect Electricity Emissions
Comment: Opposed to requirement that food processors and other industrial facilities report their consumption of electricity purchased from off-site providers. This will double-count the emissions reported by the electricity generator and the electricity user. Support an "upstream" reporting approach in which electricity providers report emissions instead of the individual users. [CLFP(10), NUMMI(34), NUMMI2(T9)] This approach will also avoid the requirement to verify individual facility data reports. [NUMMI(34)]

Agency Response: After considerable deliberation and public input, ARB determined that the needs of the GHG reporting program required by AB 32 would best be met by requiring facilities to include in emissions data reports their "indirect" electricity use. We believe this information may prove beneficial to the facility when on-site efficiency projects such as combined heat and power are developed, inasmuch as the operator and ARB will be able to track net changes in overall energy usage and emissions (e.g., increases in direct emissions relative to decreases in indirect emissions). The regulation limits this reporting to indirect energy use and energy supplier, eliminating the burden of routine indirect emissions calculation while allowing net emissions tracking if needed. Regarding the concern about double-counting emissions, indirect energy use will be reported and kept entirely independent of direct emissions produced by electricity generating facilities. Like other reported data, indirect energy use will be subject to verification to ensure completeness, accuracy, and consistency in the emissions report.

B-27. Allow More Facility Source Test Options

Comment: Allow for use of source or facility-specific emission factors instead of the factors provided within the regulation. The ARB should provide a simple and quick process for approving alternative emission factors. [CLFP(10)]

Agency Response: In very specific cases the proposed regulation allows for facility operators to measure and develop source-specific emission factors. For example operators may generate their own emission factors for the estimation of methane (CH_4) and nitrous oxide (N_2O) emissions, or the use of biomass and geothermal fuels. Although source testing was judged appropriate in these cases, ARB wanted to limit alternative means of developing emission factors to ensure consistent and comparable emissions results across facilities and industry sectors, helping to assure that "a tonne is a tonne" for each reporting facility. For appropriate flexibility we have provided operators several options for estimating their emissions. Where default emission factors cannot be used or do not adequately represent facility emissions, operators may choose to perform facility-specific fuel testing or use of continuous emissions monitoring systems (CEMS) to directly measure greenhouse emissions levels. We believe this approach provides sufficient flexibility while also ensuring consistency among reporting facilities.

B-28. Support for *De Minimis* Proposal

Comment: Support de minimis provision that would include up to three percent of facility emissions because the cost of collecting and reporting data from minor sources would be prohibitive and provide little meaningful information to ARB. [CLFP(10)] Support the decision to require reporting of "de minimis" sources with simplified accounting. [USEPA(19)]

Agency Response: Based on public input we included a *de minimis* provision in the reporting regulation that allows facility operators to use simplified methods for estimating and reporting emissions below specified thresholds, while still requiring reporting of these emissions for completeness. See section 95103(a)(6).

B-29. Use Less Certain Methods for *De Minimis* Sources

Comment: Recommend that methods associated with higher uncertainty be used for *de minimis* sources. [USEPA(19)]

Agency Response: We interpret this comment as meaning that the use of emissions calculation methods with higher uncertainty be reserved for *de minimis* sources. The comment addressed calculation of direct CO_2 from general stationary combustion sources (section 95115(b)(2)), for which several options including use of default emission factors are provided. For these facilities it was important to provide a range of options to simplify reporting while also ensuring the submittal of complete data that provides the level of certainty needed to support the reporting program. More prescriptive methods may be designated later for facilities participating in an emissions trading program. For *de minimis* sources only, facility operators may select alternative, potentially more uncertain, methods not specified in the regulation to estimate emissions, or use the methods provided in the regulation.

B-30. De Minimis Cap of 10,000 Metric Tonnes per Year is Too Low

Comment: Several comments were received stating that the 10,000 metric tonne cap for *de minimis* reporting is too stringent. Use of this threshold could require reporting of small GHG emission sources that are below the 3% threshold. Recommendations include either raising the *de minimis* cap above 10,000 tonnes or basing *de minimis* reporting strictly on a percentage of the overall facility emissions, such as 3%. [AB32IG(47), WSPA(23), CPhillips(35), APC(41), Sempra(11)] It was also mentioned that the threshold is arbitrary and it is unclear how it would be implemented for petroleum refineries and oil and gas operations, and that the *de minimis* requirements are inconsistent with some other GHG reporting programs. [API(12)]

Agency Response: Following further analysis, ARB modified the *de minimis* cap from the proposed 10,000 to 20,000 metric tonnes CO_2e (retaining the 3 percent limit) after determining the higher cap would neither significantly compromise the accuracy of emissions reports nor create undesirable disparity between large and small facilities. Though we understand the challenge of this cap for some very large facilities, a cap higher than 20,000 metric tonnes CO_2e would have resulted in *de minimis* emissions at some facilities equaling or exceeding the basic reporting threshold of 25,000 metric tonnes (the implication being that emissions of this magnitude are not always important enough to calculate and report with full accuracy). We acknowledge that our *de minimis* requirements may differ from other existing and developing GHG reporting programs. The cap is comparable to EU requirements; and the ARB 3 percent threshold, though higher than the EU, matched the proposal at the time for The Climate Registry. Based on stakeholder input on both sides of the issue (i.e., for more or less stringent reporting) we think the regulatory requirements strike the correct balance to meet program needs without imposing unnecessary reporting burdens.

B-31. Assessment of Sources Removed by Changing De Minimis to 20,000 Tonnes

Comment: Would like to see an assessment of what source streams would fall under a de minimis of 20,000 tonnes CO_2 equivalent ($CO2_e$) emissions, versus the more stringent 10,000 tonne threshold. Refinery waste water fugitive emissions may fall underneath this threshold. [ED(T18)]

Agency Response: At either threshold ARB expects *de minimis* sources to include small fugitive emission sources (leaks), wastewater emissions, space heating sources, infrequently used equipment, and other small secondary sources. Because these emissions will still be reported and subject to review by the verification team and ARB, we will be able to monitor the quantities and types of emissions reported as *de minimis.*

B-32. Fuel Activity Uncertainty Requirement too Stringent

Comment: Section 95103(a)(9). The ±2.5% uncertainty requirement is too stringent. Is it necessary to have this level of accuracy for every measurement device as long as all fuel usage is reported? Could individual accuracy requirements only be applied to larger sources or with fuel usage above a specified threshold? [ECOTEK(30)] The 2.5% accuracy requirement for fuel flow measurements is not achievable with most of the existing flow measurement devices used in the petroleum industry. Suggest that the regulations require the maintenance of flow determination equipment without creating a specific numeric performance requirement. [WSPA(23), APC(41)] Recommend that the suitability of the measurement device (based on proper design, installation, and maintenance) be considered under the verification process. [APC(41)]

Agency Response: ARB has made two changes in response to comments and subsequent investigation. We changed the uncertainty requirement (now termed accuracy) from ±2.5 percent to ±5 percent at section 95103(a)(9). We have also applied this revised requirement only to measurements used to support GHG emissions calculations. Because of the large number of fuel types and sources included in the reporting regulation, it was impractical to develop individual accuracy requirements by source type or size. We concur with the idea that verifiers will examine the suitability of measurement devices, but believe this should be done relative to requirements specified in the regulation.

Accurate fuel activity data is critical to the accurate determination of GHG combustion emissions. Accuracy bounds help to ensure emissions determinations are consistent within and across affected sectors. We think the revised requirement is reasonable and achievable with the proper operation and maintenance of measurement devices..

B-33. Provide Mechanism for Resolving Issues Such as Equipment Breakdowns

Comment: Include a process in the regulation to address unplanned events or breakdowns which would otherwise place a facility out of compliance or prevent it from achieving a positive verification opinion. [[WSPA(23)] Consider an approach that allows facilities to approach the Executive Officer to resolve issues relating to problems with verification, such as equipment breakdowns that prevent complete verification. [AB32IG(47)],

Agency Response: In response to these comments we have added a provision at section 95103(a)(10) allowing facility operators, in the event of an unforeseen data monitoring equipment breakdown, to make a request to the ARB Executive Officer to approve interim data collection procedures during the breakdown. Executive Officer approval does not guarantee the procedure will support a positive verification opinion, however. The verification team will evaluate whether the use of the interim data collection method is adequate to meet the accuracy and completeness requirements of the regulation.

B-34. Consider Alternate Wording for Missing Analytical Data
Comment: Page A-23 of Attachment A of Staff Report. Suggest alternate wording for handling missing analytical data as specified in section 95103(a)(8)(A)&(B). Replace sections with, "When the applicable emissions estimation methodologies in sections 95110 through 95125 require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year. Whenever valid oil or natural gas fuel analytical data cannot be obtained, the missing data procedures in Part 75, Appendix D, Section 2.4 shall be used to provide substitute GCV or fuel flow rate data." Commenter states that by using this type of approach, a complete data set will always be obtained, and there will be incentive for properly maintaining fuel sampling and analysis equipment. [USEPA(19)]

Agency Response: ARB appreciates the suggested alternate wording intended to assure the availability of data or conservative alternatives. When the reporting entity is using data collected under CFR Part 75 or Part 60 in order to report to ARB, the approach mentioned is already required to meet the stipulations in 40CFR Part 75 and Part 60. For facilities already reporting under federal mandates, following federal regulatory data collection procedures insures that information submitted to ARB is consistent with the federal data. For other facilities where the capture rate is below 80 percent, the mean of the available data best represents the actual emissions at the facility. To assure data quality, data assembled during interim data collection periods are subject to Executive Officer approval.

B-35. Require Recordkeeping for Measurement Devices
Comment: Suggest adding the following sentence to the end of 95103(a)(9): "Documentation, e.g., section from user manual, test results, etc., shall be submitted to ARB (or maintained on-site?). This documentation shall be

sufficient to support the claim that the maintenance and calibration frequency is sufficient to maintain this uncertainty level." [USEPA(19)]

Agency Response: Additional text was added to the regulation at section 95103(a)(9) to require the maintenance of data to support demonstration of the specified level of accuracy. ARB did not require submission of this documentation as a matter of routine because the information is not useful, on an ongoing basis, for meeting ARB program needs. ARB may request the information from facility operators at any time as specified by section 95105(b).

B-36. Remove Requirement to Commit to Fuel or CEMS Method, 95103(a)(10)
Comment: Section 95103(a)(10). Rather than forcing certain facility operators to select a single method to estimate emissions (either CEMS or fuel-based) and having them commit to that method indefinitely, facilities should be allowed to select between the options provided within the regulation as needed to provide the best available data. [ECOTEK(30), Praxair(22), APC(41)]

Agency Response: The Act requires the regulation to "ensure rigorous and *consistent* emissions accounting," which is essential to any accurate GHG reporting program. Our concern is that different measurement approaches often produce different results due simply to the variation in method. If facilities select one measurement approach for reporting some years, and another measurement approach for other years, the data sets will not be comparable over time, making problematic the tracking of progress and undermining the usefulness of the collected data. We therefore find it necessary to require operators to select a single method to develop their "baseline" and hold onto that method, at least after the initial ramp-up year. The regulation has also been modified to provide two additional years to operators who do not yet have CEMS in place, to complete installation in time for 2011 monitoring.

B-37. Make Reporting Dates Consistent for All to Provide Additional Time
Comment: For all facilities, allow additional time for reporting. Instead of requiring reporting on April 1 of each year and verification by October 1, require reporting by June 1 and verification by December 1. [CLFP(10)]

Agency Response: We understand the desire for additional time for reporting, which would occur for some facilities if we delayed reporting dates until June 1 for all facilities. However, to effectively meet program needs it is necessary to stagger due dates for emissions reports. Those facilities that generally have less complex emissions data reports are required to report by April 1 of each year. This includes general stationary combustion facilities and electric generating facilities and cogeneration facilities not tied to larger facilities or retail providers. More complex facilities requiring specialized methods and entities reporting electricity transactions are provided additional time and must submit emission reports by June 1 each year. The staggered schedule will reduced deadline bottlenecks and help assure reporters have access to the technical assistance and verification services they need. ARB believes the reporting and verification deadlines are reasonable and achievable for both groups of reporting entities.

B-38. Reporting Schedule – Provide Additional Time

Comment: Concern that despite the best efforts of the regulated community, it may not be possible to specify, solicit bids, purchase, install, calibrate and place in service monitoring equipment within the 12 months allotted by the proposal. Should this situation arise, the program should include a provision for a temporary alternate calculation method that would be approved by the ARB and include obligations on the regulated entity for timely completion of the required components. It would be inequitable to pursue some type of enforcement activity against an entity for matters beyond our control, particularly when there likely are adequate temporary alternatives available. [CPhillips(35)]

Agency Response: The regulation includes a provision to allow 2008 emissions reported in 2009 to utilize best available methods and data in lieu of the full data and method requirements in the regulation. Facility operators have known since Board approval in December 2007 that regulations were being adopted that require fully compliant reports beginning in 2010, giving operators additional lead time to plan their reporting programs. However, any facility or entity that believes complete reporting using full regulation specifications will be impossible in 2010 should discuss this matter as early as possible with ARB staff.

B-39. Make ARB and CCAR Reporting Schedules Align

Comment: For continuity and to ease the GHG reporting process, the ARB mandatory reporting dates should be made consistent with the voluntary California Climate Action Registry (CCAR) reporting schedule. [BACWA(44)]

Agency Response: ARB received input from several stakeholders urging that more time be allowed for verification than was allowed under the CCAR schedule. We thought this was important, particularly since the ARB mandatory program will include at least 850 reporting facilities and entities, several times more than report to CCAR. To allow six-month verification periods to be completed in the report year so that data can be made public early the following year, earlier reporting due dates are necessary.

B-40. Change the Reporting Date

Comment: Change the reporting due date to May 1, which is nearer to the May 31 due date for annual Air Pollution Control District emissions statements. [MKP45)]

Agency Response: The comment was received from an independent oil and gas producer. The GHG emissions data report due date for facilities in the oil and gas sector is June 1. Reducing the reporting time by one month would likely produce hardships on some operators of complex facilities. The regulation does not preclude the early submittal of data. Facility operators with the June 1 reporting deadline are free to submit their annual GHG emissions reports on May 1, or any other date of their choosing that is on or before June 1st of each year.

B-41. Allow Reporting in 2011 Instead of 2009 for Small Businesses
Comment: For small businesses, such as independent crude oil and gas producers, require reporting of fugitive and combustion emissions in the year 2011 instead of 2009. Otherwise there will be two different reporting and verification schedules. [MKP(45)]

Agency Response: For purposes of clarification, ARB notes that all oil and gas producers and refiners, as well as utilities and power transmission companies generating and transmitting more than 4.5 million kWh annually, are specifically excluded from the Administrative Procedure Act's definition of "small business" regardless of the actually size of the business. See Government Code section 11342.610(b)(8)-(9). Due to the aggressive timelines provided in AB 32 for GHG emission reductions, it is critical that facility GHG emissions reporting commence as soon as possible. ARB believes it is reasonable for facilities to report using best available data a methods beginning in 2009. However, we have adjusted the schedule so that all facility emissions from oil and gas producers are reported on the same schedule (section 95103(b)(2)(C)). Also note that at this time oil and gas production facilities are not required to report fugitive emissions, pending the development of complete and appropriate calculation methodologies and their incorporation through a subsequent regulatory process.

B-42. Require Triennial Verification Sooner for Some Facilities
Comment: Require entities subject to triennial verification to fully comply with mandatory reporting requirements, including third party verification, in 2010 when reporting their 2009 emissions, rather than in 2011 as proposed. [NRDC(15, T1), UCS(T17), ED(T18), ALA(T22)]

Agency Response: The Board directed staff to make this change at the board hearing on December 6, 2007. Mandatory verification for all reporting facilities now begins in the year 2010.

B-43. Clarify Why Some Facilities Report Annually and Some Triennially
Comment: Staff Report page 12. It is unclear why some facilities are required to report annually and others report triennially. Additional explanation should be provided. [USEPA(19)]

Agency Response: All facilities subject to the regulation are required to submit an emissions data report each year. However, specified types of facilities, which are smaller or have stable and less complex emissions to report, are permitted to forgo the less intensive interim year verifications between the full verifications that are required of all facilities triennially. Because their calculation methods and assumptions are typically straightforward, and because the annual reports for these facilities can be easily checked against other data sources by ARB staff, we concluded it was an unnecessary burden to require that verification be revisited annually for these facilities. Note that annual verification will be required for any facility later included in a GHG market or trading system.

B-44. Triennial Schedules for Pure Biomass Facilities

Comment: Section 95103(c)(2) states that only pure biomass electric generating facilities may use a triennial schedule. Why was the word "pure" used here? Is an MSW electric generating facility > 10 MW subject to an annual schedule as in 95103(c)(1)? And was this your intent? [Covanta(1)]

Agency Response: In the proposed regulation a biomass fuel is considered pure when the fraction of biomass carbon accounts for at least 97 percent of the total amount of carbon in the fuel. See section 95102(a)(164). These all-biomass facilities are by design on a triennial verification schedule, along with facilities with total nameplate generating capacity of less than 10 MW. Facilities 10 MW or higher that burn municipal solid waste (MSW) are required to verify their data annually.

B-45. Change Verification Schedule for Hydrogen Plants

Comment: Request: 1) requiring triennial rather than annual verification for hydrogen plants and, 2) requiring verification starting two years later, in 2012 rather than 2010. [Praxair(22)]

Agency Response: Hydrogen plants are large GHG sources sometimes operated as a stand alone facility but often an integral part and under operational control of a refinery. The complexity of a hydrogen plant's operations warrant an annual verification of the emissions data reports. ARB considers it important for all facilities to be verified beginning in 2010, whether they were subject to triennial or annual verification. This helps to establish an accurate and trustworthy GHG emissions inventory to support ARB GHG reduction programs and goals.

B-46. Consider More Frequent Reporting for Regulated Sources

Comment: Could consider requiring more frequent reporting (e.g., quarterly) if regulations are passed requiring GHG reductions. This could potentially reduce the number of enforcement cases. [USEPA(19)]

Agency Response: ARB understands that more frequent reporting may be necessary to support a cap-and-trade program or other future regulations, but does not find it warranted at this point. AB 32 requires annual reporting, and this is sufficient for current emissions inventory and tracking needs.

B-47. Do Not Allow Facilities to Stop Reporting Due to Emissions Reductions

Comment: Staff Report page 8. Do not allow facilities to stop reporting if their emissions are below 20,000 tonnes for thee years in a row. Advise a "once in-always-in" approach to reporting. [USEPA(19)]

Agency Response: Although we expect many facilities that later fall below the 20,000 tonne threshold to continue reporting on a voluntary basis due to the benefits of tracking their GHG emissions levels, ARB finds it difficult to justify a requirement for reporting in perpetuity regardless of emission levels. Applicability is based on our assessment of "significant" GHG emitting facilities, and we believe that facilities that substantially reduce emissions below regulation thresholds due to technology improvements or curtailed operations should be relieved of the reporting requirement.

B-48. Allow More Flexibility for Data Gathering and Calculation Methods

Comment: The regulatory language does not contain flexibility which would lessen the reporting burden when reporters could demonstrate the validity of alternative methods, or allow for the use of emerging new technologies. [API(12)] Provide flexibility for data gathering/calculation methodology modification with Executive Office approval. [AB32IG(47)] The current regulation does not provide the flexibility to incorporate "improved" accounting methods because reporters are required to use the specific approach in the rule. Provisions should be included to allow EO approval of modifications to calculation methods. [WSPA(23)]

Agency Response: GHG emission calculation methods, equations, and emissions factors were specified in the regulation in order to ensure that emissions accounting is consistent and rigorous, as required by the Act. Consistency and accuracy are essential cornerstones of a valid reporting program, helping to ensure the validity and fairness of results. In addition, submittal of alternative methods for approval would lead to time-consuming and cumbersome methodology review processes and less certainty for regulated entities.

In situations where variations in operational parameters may be anticipated, flexibility has been incorporated into reporting methods. Some procedures involving the Executive Officer have also been judiciously included in the regulation, including requirements affecting unforeseen breakdowns in monitoring, and disagreements on the verifiability of submitted emissions data reports. To the extent that standardized new methods emerge, ARB will consider adding them to the regulation during future amendments.

B-49. Fleet Owner Should Report Mobile Emissions

Comment: Regarding mobile emissions, it is CLFP's view that if, at some point, ARB requires that fleet emissions be reported, then the fleet owner should be responsible for the emissions reporting and not the customer of the trucking services or the sites that the vehicles may visit. This would be the most accurate and simple approach. Finally, emissions emanating from any mobile rental equipment should be attributed to the rental agency and the stationary facility renting the equipment (similar to ARB's forklift rule). [CLFP(10)]

Agency Response: Mandatory reporting of mobile emissions is not required by this regulation; any future amendments to include mobile sources for mandatory GHG reporting will be subject to a full public process for stakeholders to provide input. The regulation requires that stationary combustion source emissions be reported by the entity with operational control of the equipment. Rental equipment that meets the regulation's definition of "portable," however, is not subject to inclusion in emissions reports.

§95104 Greenhouse Gas Emissions Data Report

B-50. Electronic Reporting and Data Security
Comment: Provide a mechanism for electronic reporting of GHG emissions. Take special precautions to ensure the security of the data. [CLFP(10)]

Agency Response: We will provide electronic online tools for those who choose to report GHG emissions in that manner. This will provide an efficient mechanism for reporting facilities to meet the data reporting requirements of the regulations. The ARB will ensure that multiple levels of protection are provided regarding the security to the data. Data will be housed on firewall protected servers. Access to data will be password protected and structured in a hierarchal fashion so that data will be compartmentalized and access controlled. For example, facility operators will have password protected access to only their data, but not access to the data of others. We will make all reasonable efforts to ensure that submitted data remain secure.

B-51. Require Electronic Submittal Using Standardized Formats
Comment: Strongly advise submission of emission reports electronically in a standardized format to ease quality assurance/quality control (QA/QC) and analysis efforts. [USEPA(19)]

Agency Response: We agree. ARB will provide an online tool that can be used for the reporting of GHG emissions required by the regulation. AB 32 in fact requires ARB to provide such tools.

B-52. Remove Requirement for Reporting Subsidiary Facilities
Comment: The requirements in section 95104(a)(8) and (9) that reporting facilities also report name, location, and contact information for subsidiary facilities is overly broad and will not result in the collection of information useful to future ARB program development. The effort required would be burdensome and the data would quickly become obsolete. Recommend that the scope of this

section be narrowed to collect information only from facilities that generate GHG emissions from their own operations (and not from the purchase and use of energy). Offices and retail stores should be specifically exempted. Also, ownership share in a facility is not pertinent to GHG emissions inventory and the requirement to submit this information should be deleted. [PPG(17)] Requirement imposes significant burden on petroleum refineries affiliated with retail providers and is unnecessary and should be deleted. [EPUC/CAC(42)] Only sources that emit GHGs should be required to report. [WSPA(23)]

<u>Agency Response</u>: We have modified the original proposal to address these concerns. Under the revised proposal, only those subsidiary facilities that emit direct GHG emissions from combustion, not including space heating, are required to be reported. This provision will generally exempt offices and retail stores from having to be reported. We have also removed the requirement for reporting ownership share from section 95104(a) because we agree it is not necessary for developing facility emission estimates or identifying emitting facilities. Finally, the revised language stipulates that the data collected to meet this requirement is not subject to verification.

B-53. <u>Remove the Requirement to Report Company Equity Shares in Facilities</u>
<u>Comment</u>: Amend the draft regulation to delete equity reporting because it adds enormous complexity and does little to enhance emission tracking. [AB32IG(47)] Requirement that companies provide ownership share and operational control information is extremely burdensome. [API(12)] Equity share reporting is not germane to GHG reporting. [WSPA(23)]

<u>Agency Response</u>: We have removed the requirement to report equity share or ownership share from section 95104(a). Retail providers of electricity are still required to report their ownership share in electric generating facilities under section 95111(b)(3)(Q). This is because ARB has not yet determined the design of future regulations for the electricity sector, and some of the alternatives being considered may require this information. For operators of other facilities we agree the requirement is unnecessary at this time.

B-54. <u>Delete Provisions Requiring Reporting of Unverified Data</u>
<u>Comment</u>: Delete provisions in the regulation requiring facilities to report unverified data because the data adds little to tracking actual emissions but could be inadvertently disclosed with negative consequences. Only allow submittal of verified data. [AB32IG(47)]

<u>Agency Response</u>: Our intent is generally to rely on verified data in producing public emissions reports. Under the regulation, reporting and verification occur in several sequential steps. First, the emissions data report is submitted to the ARB as the data of record for verification. The report is then reviewed for verification by an independent third party. If the report meets the specifications to be verified, it will be designated in the ARB data system as having received a

positive verification opinion. When a report cannot be successfully verified, the facility operator will be permitted to make modifications. If the verification body finds the changes satisfactory such that a positive opinion is possible, this will be designated in the ARB data system. If the report cannot be verified at the conclusion of the six-month verification period, an adverse opinion will be filed and this will be noted in the data system.

Initially, unverified data is submitted to ARB to establish a process that will preserve independent review by the third-party verification team. Without it, operators could work iteratively and continuously with verifiers (who are effectively hired to make the data verifiable) until they receive a positive verification opinion. Conflict of interest concerns may arise when verifiers are asked to "fix" emissions reports and critique their own work. ARB regards unverified data to be preliminary and does not intend to routinely publish emissions data prior to verification. The Public Records Act, Government Code Section 6255 et seq., governs ARB's response to public requests including unverified data. See section 95106 of the regulation regarding the submission of confidential information under this article.

§95105 Document Retention and Record Keeping Requirements

B-55. CEMS Measurement Method Data Requirements, Section 95105(d)(6)
Comment: Recommend that ARB provide clarification of what level of technical description and documentation of the approval from, and definition of, a competent authority for CEMS. [APC(41)]

Agency Response: Section 95125(g) specifies the requirements for existing and new CEMS. These requirements document the level of technical description, documentation, and other information required when CEMS are used.

§95106 Confidentiality

B-56. Public Disclosure and Confidentiality
Comment: Only provide public disclosure of total greenhouse gas emissions from each facility. There is no need for the public to know energy consumption, process information, or other commercially sensitive information. This sensitive information should not be released without written permission from the reporting facility. [CLFP(10)] Provide more specific reference to the trade secret provisions of the Public Records Act in the regulations. Release sensitive reporting information on an aggregated basis only. [AREM(T16)]

Agency Response: Under State law, emissions data are required to be public information and cannot be claimed as confidential. This requirement also applies to individually reported facility processes. Therefore, we are unable to include a provision in the regulation which would allow only disclosure of "total" facility or aggregated GHG emissions. For reporting purposes the regulation does allow for the grouping of emissions from some facility emission sources which will, in some cases, address the concern of pubic disclosure of emissions from individual facility processes. For other non-emissions data submitted to the ARB, as specified in section 95106 of the regulation, facility operators may claim information as confidential in accordance with the procedures specified in title 17, California Code of Regulations, sections 91000 to 91022. The ARB data reporting systems will include mechanisms for facility operators to easily identify as confidential any non-emissions data they believe are trade secret or otherwise confidential.

B-57. Adopt Confidentiality Provision as Proposed

Comment: Section 95106 specifies what data must be made publicly available. The current draft requires only that the total emissions data be made public. Other data, used to calculate indirect emissions, is not required to be made public and the reporter can protect its confidentiality. EPUC/CAC supports this provision. Such data on the indirect use of electric and thermal energy can be commercially sensitive and should not be disclosed. Particularly with the requirement for third-party verification, there is no need for the public to have access to such supporting data. [EPUC/CAC(42)]

Agency Response: Non-emissions information that the submitting entity has identified as confidential will be handled in accordance with the procedures specified in title 17, California Code of Regulations, sections 91000 to 91022. Regulatory language has been modified to state clearly that emissions data is public information as provided in existing law. This is not limited to facility total emissions. While we cannot say at this time whether the data that the commenter refers to is confidential, if it is not emissions data, the reporting entity can submit it under claim of confidentiality and ARB will follow the process in title 17, California Code of Regulations, sections 91000-91022 before disclosing it.

B-58. Prevent the Release of Unverified Data

Comment: Emissions data is sensitive in that its release may affect market conditions (should a market develop). Annual verified data should be released by ARB to the public annually at a prescribed time to avoid placing any reporter at a competitive disadvantage. [WSPA(23)]

Agency Response: ARB agrees that the timing of public data releases should consider fairness for emissions markets, should they be part of the Board's adopted reductions strategy. This issue will be addressed during the development phase of a potential market.

B-59. Confidentiality of Detailed Transaction Data

Comment: Any reporting program established must maintain the confidentiality of market sensitive information and avoid disclosure of detailed transaction data.

Urge the ARB to modify the Staff Report and the proposed rules to provide greater specification as to the Government Code section that provides confidentiality protection to LSEs that file reports to ARB. [AREM(46)] Suggest there be a more specific reference to the trade secret provision of the Public Records Act in the regulation. Request that very sensitive information be made public on an aggregated basis only. [AREM(T16)]

Request that ARB's confidentiality requirements be consistent with FERC requirements for wholesale transactions. In addition, ARB should consider revising Section 95106 to be consistent with CPUC Decision 06-06-066 which provides more adequate protection in the treatment of confidential electric procurement data. [LADWP(BH6)]

Agency Response: ARB has long established regulatory procedures for addressing the matter of potentially confidential data. The database will enable reporting entities to claim any information other than emissions data as confidential. Public inquiries related to information so designated will be handled in accordance with the procedures specified in title 17, California Code of Regulations, sections 91000 to 91022. In addition, sections 95111(b)(1)(A) of the regulation require that electricity transactions be reported in aggregate and not by individual transaction.

§95107 Enforcement

B-60. Clarify Enforcement Section

Comment: Suggest changes to the enforcement provisions to improve clarity as provided in Attachment B of WSPA comments. As written, the enforcement provisions could be read as allowing multiple charges for minor offenses, such as being 7-days late in report submittal. Staff presentations at the workshops, and in our staff conversations, indicated that the intent of the enforcement provisions was to assure compliance rather than being punitive. Prefix section 95107(a) with, "Failure to submit any report or to include in a report all information required by this article, or." Add an additional section (c) to state, "Failure to include in a report the information specified in sections 95104(a)(8) and (a)(9) shall not be considered a violation of this article." [WSPA(23)] Provide clarification in the enforcement section (95107) to ensure compliance without being punitive as was discussed in public workshops. [AB32IG(47)]

Agency Response: Section 95107 on Enforcement has been modified to clarify what constitutes a violation. The suggested text above, beginning with "Failure to submit any report…," was prefixed to section 95107(b) to make the requirements more specific. The addition of a section (c), as suggested, was not necessary. Instead, text was added to the end of section 95107(b) to clearly define what is meant by "report" for compliance purposes. This should address the concern. ARB intends to enforce the regulation and apply penalties where warranted. Nonetheless, ARB is committed to assisting reporters through instructional guidelines, efficient reporting tools, training, phone and email responses to questions, and other means needed to help those who want to comply with the regulation successfully.

B-61. Enforcement if Verifier Does Not Submit Information

Comment: The verifiers play a critical role in the process; however, their responsibilities must not negatively impact an entity's ability to positively demonstrate compliance. If an entity satisfies all its obligations to provide its emissions report to a qualified verifier in a timely manner, the entity should not be exposed to any penalty do to a lack of performance by the verifier. Section 95103(c)(3) should be clarified to specify that there is a burden on verifiers to satisfy the time constraints of this section.
[CPhillips(35)]

Agency Response: Section 95103(c)(3) has been modified to specify the responsibility of the verification body to submit the verification opinion. The verification opinion has also been included among the reports subject to potential enforcement action in Section 95107. In cases when an enforcement action is taken, ARB will focus on the party (or parties) responsible for the non-compliance. We encourage facility operators to seek verification services early in the process so that verifiers are not put into the position of receiving a report for verification with insufficient time to perform the required work.

B-62. Recommend Late Fees Instead of Daily Violations for Missing Reporting or Verification Deadlines

Comment: Section 95107(b) of the mandatory reporting regulation states that failure to submit any report or include all information required in the report by the specified reporting dates "shall constitute a single, separate violation" for each day. This would apply to emissions data reports, the verification opinion, or any other document required to be submitted. During workshops and in previous comments, LADWP recommended that the deadline for submitting the verification opinion should not be subject to enforcement, since issues beyond the control of the reporter may arise during the verification process that require extra time to resolve. Rather than imposing daily violations for late reports or missing information, we believe the policy used by the local air districts for late submittal of emission reports is more reasonable and appropriate. For example, if a reporter does not submit their emissions report and fees to the South Coast Air Quality Management District (SCAQMD) by the deadline, SCAQMD charges escalating late fees rather than treating it as a violation. [See SCAQMD Rule 301 (e)(10)] Considering the fact that ARB's mandatory greenhouse gas emissions reporting program is new and many reporters will be submitting and verifying their greenhouse gas emissions reports for the first time, we believe daily violations should not be applied to late submittal of emissions data or verification opinions. A nominal late fee or other means of encouraging compliance would be more appropriate. [FF(11)]

Agency Response: AB 32 does not expressly give ARB authority to impose late fees. Rather, ARB is given authority to enforce the regulation through existing enforcement statutes, including collection of penalties, and to collect administrative fees. Late filing fees as proposed by the commenter would be neither a penalty for violation nor an administrative fee, which makes it unlikely ARB has authority to establish such fees independent of the enforcement process. Furthermore, Health & Safety Code section 38580 classifies any failure to comply with the regulation as a violation enforceable under that section, which suggests that ARB does not have authority to consider missed deadlines as something other than a violation of the regulation. ARB appreciates that the regulation is new and complex. If reports are not filed on time, ARB will consider all relevant circumstances of the situation, including efforts by the operator or verifier to meet the deadlines, in deciding what enforcement action is appropriate.

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

§95110 Data Requirements and Calculation Methods for Cement Plants

C-1. Clarify Reporting for Landfill Gas and Biogas
Comment: It is not clear that emissions from the combustion of landfill gas or biogas should be calculated but not included in facility totals. [USEPA(19)]

Agency Response: Emissions from landfill gas or biogas are to be estimated and included in the facility GHG emissions report and the facility total emissions. For cement plants this requirement is specified in section 95110(a)(3)(D). Total CO_2 emissions by fuel type must be reported and CO_2 emissions from biomass-derived fuels must be reported separately as a subset of the total emissions. Combustion emissions from biomass-derived fuels will be accounted for separately in the ARB database.

C-2. Typo in Section 95110(c)(2)
Comment: Section 95110(c)(2). Typographical error, “assumed” is listed twice on third line. [ECOTEK(30)]

Agency Response: The error has been corrected.

C-3. Allow Fuel-Specific Emission Factors for Alternative Fuels
Comment: The Cement industry supports the expanded use of alternative fuels such as biomass, tire derived fuel, biosolids, municipal solid waste and others... Considering the approach of developing fuel-specific emission factors by measuring heat value and/or carbon content of the fuel, the cement industry has identified specific laboratory methods to measure these values. Consequently, the following changes to the regulation language are requested to incorporate

these methods. Apply the heat content method for middle distillates and oil to liquid alternative fuels. For heat content measurements for wood pellets use ISO 1928 or ASTM D5865-02. For other solid alternative fuels including but not limited to biomass and wed and dried biosolids use ASTM D5468 or D5865-02. For carbon content, include the use of ASTM D-5373-02 for wood pellets and ASTM 5373-02 for solid alternative fuels including and not limited to biomass, and wet and dried biosolids. For liquid alternative fuels use ASTM D5291-02. [CCMEC(9)]

Agency Response: ARB included several changes to provide cement plant operators with more options for calculating stationary combustion emissions by fuel type. The original proposal included an option for cement plant operators to calculate CO_2 emissions associated with biomass using a default emission factor or a source test method. The final proposal expanded those options to allow for operators to measure heat content or carbon content of biomass fuels. An additional change was made to allow operators of cement plants combusting alternative fuels to have the option of using a source test method to calculate CO_2 emissions.

Based on the comment, the regulation was updated to allow use of all of the methods provided in the comment (updated to the most current versions) with the exception of the ISO 1928 method. Generally we have specified ASTM methods for consistency and the ASTM method is sufficiently equivalent to the ISO method that we choose not to include both options. ARB updated the Additional Methods section 95125 to include the referenced ASTM standard test methods for liquid alternative fuels, solid alternative fuels, biomass, dry biosolids, and wet biosolids and ARB included the most current ASTM standards of the methods referenced in the comment letter.

§95111. Data Requirements and Calculation Methods for Electric Generating Facilities, Retail Providers and Marketers

C-4. SF_6 Reporting Clarification
Comment: Page A-38, section 95111(a)(1)(J) – Clarity would be increased if text of subparagraph was changed to read, "Fugitive SF_6, in kilograms, emitted from equipment that is located at the facility and that the operator is responsible for maintaining in proper working order." [USEPA(19)]

Agency Response: The regulation was modified to reflect this comment.

C-5. Report SF_6 by entity
Comment: Due to the manner in which SF_6 is used in the field, reporting on a facility level may prove to be very difficult. Request that an option be provided to report this information on an entity basis. [Sempra(11)] Request modifications related to reporting fugitive SF_6 from multiple individual units. [Sempra(T20)]

Reporting and verification of SF_6 emissions by retail providers should be handled as a single facility. [LADWP(BH6)]

Agency Response: ARB added language to section 95111(a)(1)(J) to allow retail providers to aggregate SF_6 emissions for all sources or any subset of sources.

C-6. Option to Use CEMS or Fuel-Based Methods
Comment: Recommend adding the option for all electric generating facilities to choose whether to report emissions using either CEMS or a fuel-based method. Having the option will enable each facility to utilize the most accurate method to calculate and report emissions for their particular facility." [LADWP(BH6)]

Agency Response: ARB does not agree that a change is needed. Operators subject to the U.S. EPA acid rain program may elect to report using CEMS or a fuel-based methodology as available within that program. This approach maintains consistency between information reported to California and to U.S. EPA. See Section 95111(c). Facilities that combust certain complex fuels like municipal solid waste are required to use CO_2 CEMS data if available. Other facilities not subject to the acid rain program do have the option to report using a CEMS methodology or a fuel-based methodology.

C-7. Retail Providers – Emissions Responsibility
Comment: Page A-40 of Staff Report, section 95111(b)(2)(A) - Paragraph states that retail providers report fugitive emissions from transmission and distribution systems that are located inside California and that the retail provider is responsible to maintain. However, the preamble states that the regulation does not assign responsibility for these emissions to the reporting retail provider. It seems appropriate to assign responsibility when the emissions occur within the state of California and the retail provider is responsible for the equipment from which the emissions occur. [USEPA(19)]

Agency Response: The mandatory reporting regulation requires operators of generating facilities, retail providers, and marketers (when applicable) to report fugitive SF_6 data. During future development of emission reduction regulations, ARB will decide whether assigning responsibility for fugitive emissions is appropriate and, if so, how to distribute them among many providers or users of the transmission and distribution system.

C-8. Consider Additional QC/QA Checks and More Frequent Sampling
Comment: Page A-45 of Staff Report, section 95111(c)(2) - Appendix G fuel-based methods for oil- and gas-fired units are considered to be of higher accuracy than for coal-fired units because of the greater homogeneity of the fuels, and because of strong fuel flow meter QA/QC requirements in Part 75, Appendix D. However, EPA does not discount the possibility that further quality assurance requirements and auditing provisions may be necessary to better ensure that data from Appendix G methods for solid fuels are comparable to data

from CEMS. For example, ARB might consider adding QA/QC checks for solid fuel feed rate equipment. Daily or hourly coal sampling and analysis rather than weekly might also be desirable. [USEPA(19)]

Agency Response: ARB anticipates that the vast majority of stakeholders who combust solid fuels and who have CEMS systems will use CEMS data for reporting. However, we have provided the option to use other methods outlined in Appendix G to give flexibility to the minority of stakeholders who have less confidence in their CEMS systems that do the majority. In section 95103(a)(9), the regulation requires facility operators to ensure a fuel activity accuracy of $\pm$5 percent and to maintain and calibrate equipment to meet these requirements. ARB also considered increasing the number of coal samplings and analysis, but chose to remain consistent with current U.S.EPA regulations and guidelines on fuel-based methods for solid fuels.

C-9. Consider Requirement for CO_2 (or O_2) CEMS and Flow Monitor
Comment: Pages A-45 and A-78 of Staff Report, section 95111(c)(2)(A) and section 95125(g). Consider requiring facilities that are subject to 40 CFR Part 75 and have a CO_2 (or O2) CEMS and flow monitor to use them to report CO_2 before GHG reduction regulations are enacted by ARB (based on the above statement about current QA/QC procedures). [USEPA(19)]

Agency Response: When facilities are subject to federal regulations, ARB requires these facilities to report information to ARB that is consistent with the information they report to U.S. EPA. ARB recognizes that it may be necessary to revise reporting requirements in the future to be consistent with regional or national trading programs. The use of CEMS-based methodologies for reporting CO2 emissions is one area that may need future review.

C-10. Additional Effort May be Needed to Refine Carbon in Fly Ash Assumptions
Comment: Page A-45 and A-71 of Staff Report, section 95111(c)(2) and section 95125(a)-(d)(1). Fuel-based methods also rely on an assumed loss of carbon in fly ash and from conversion to carbon monoxide. Additional work may be required to refine these numbers. [USEPA(19)]

Agency Response: Equations in the regulation assume 100% conversion to CO_2, consistent with international practice in computing these emissions. We will continue to monitor the evolution of standard practices regarding how fly ash is considered and adjust the regulation as warranted for consistency.

C-11. Comments on Biomass and Municipal Solid Waste Reporting
Comment: Measuring the amount of biomass municipal solid waste is very challenging. ARB might consider using CEMS or additional QA/QC for fuel consumption along with frequent fuel analysis. Consider the application of stack monitors. [USEPA(19)]

Agency Response: All facilities that combust biomass and municipal solid waste and have CO_2 CEMS systems are required to report using CEMS data. ARB did not choose to require these facilities to incur the added expense of installing CEMS. Comment D-1 discusses QA/QC requirements for facilities that combust solid fuels but do not have CEMS.

C-12. Enhance Method for HFC Reporting by Including Other Emissions
Comment: Staff Report page A-48, section 95111(h). The current approach for reporting HFCs from an individual cooling unit will include emissions that are placed into operating equipment, but may not capture emissions from initial charging, emissions between the final refilling and retirement, and emissions during retirement. The regulation should include additional equations and reporting requirements to capture these additional HFC emissions. Suggest using 2006 IPCC equations provided in comment letter. [USEPA(19)]

Agency Response: ARB has revised section 95111(h)(1) to include a methodology based on U.S. EPA recommendations and the Climate Leaders Greenhouse Gas Inventory Protocol for fugitive HFC emissions.

C-13. Reporting 40 CFR Part 75 CO_2 Emissions at Unit Level
Comment: Facility has one gas turbine/generator that is subject to 40 CFR 75, and several other turbine/generators and boilers that are not. It is not possible to report Part 75 CO_2 emissions at the facility level. We can only report Part 75 CO_2 emissions for the turbine generator that is subject to this regulation. The language in Section 95111(c)(1) should be written so that it is clear the requirement to report Part 75 emissions apply at the unit level for those units subject to Part 75, and not the facility level. [RPower1(2)] It is not possible to report Part 75 CO_2 emission at the facility level for Redding Power because we can only report Part 75 CO_2 emissions for the turbine generator that is subject to this regulation. We recommend that Section 95111(c)(1) be changed. [REU(18)]

Agency Response: ARB agrees and has modified the language at section 95111(c)(1) to allow such data to be reported at the unit or facility level.

C-14. Wholesales Sales that Sink in California
Comment: Requiring retail providers to prove electricity sales sink in California will lead to double counting of emissions and may impose unnecessary costs on California Customers. [PGE(13), SCE(16)]

Agency Response: ARB accepts this recommendation. Section 95111(b)(3)(I) has been renumbered to 95111(b)(3)(J) and revised to require retail providers to designate a wholesale sale as inside California if the point of delivery of the sale is within California. When this cannot be documented, the (non-multijurisdictional) retail provider will report the sale as an export. The revision simplifies the tracking of wholesale sales to end at their point of delivery, and removes the requirement for retail providers to seek further documentation on the final sink for transactions.

C-15. Treatment of Substitute Power and California Eligible Renewable Resources

Comment: Reporting regulations should support and be consistent with California's statutory preference for eligible renewable energy resources. . . Certain types of arrangements which provide renewable energy to California may be inadvertently affected or even prohibited by the reporting regulations as proposed. ARB should add the language, "including any California eligible renewable resource" to the definition for specified source of power in section 95102(a)(166). ARB should delete the definition for substitute power in section 95102(a)(173) and delete section 95111(b)(1)(A)(10) that requires reporting of substitute power. Alternatively, ARB should exclude eligible renewable energy from the definition of substitute power. [PGE(13)]

Agency Response: ARB has modified the regulation to address the commenter's concerns. ARB added language in section 95102(a)(166) to read "including any California eligible renewable resource." ARB also deleted reporting requirements specific to substitute energy in section 95111(b)(1)(A)(10) and deleted the definition for "substitute energy" at section 95102(a)(173). ARB chose these revisions because the regulation requires reporting of all power as specified or unspecified, regardless of whether the power is substitute energy or not. It is not necessary to identify substitute power separately from other power transactions. If this distinction is needed in future emission control regulations, ARB will revisit the reporting requirements.

C-16. Substitute Energy for Firming Renewable Resources

Comment: In the proposed regulations, section 95111(b)(1)(A)(10) provides that retail providers and marketers shall "[s]pecify purchases of substitute energy and provide the same information required for other types of power purchases in this article as applicable." Retail providers must be permitted to utilize existing firming contracts for renewable resources such as wind. Wind is an intermittent resource that must generally be firmed by thermal generation. The typical firming contract, however, results in the full contracted amount of renewable energy being delivered to the retail provider. In order to encourage the building of new renewable generation, the regulations should recognize firming contracts using substitute power as an acceptable form of prudent utility practice. Section 95111(b)(1)(A)10 of the proposed regulation should be replaced by adding the following language at section 95111(b)(2)(H):

Power purchased from identified California eligible renewable resources in which the generating facility is an intermittent resource in which the reporting entity has retired the WREGIS certificate. The retail provider or marketer shall specify the energy purchases from the intermittent renewable resource or from substitute unspecified resources that do not exceed the total reasonably expected output of the identified renewable power plant over the term of the contract. [CMUA(25)]

Agency Response: In response to this and other comments (see comment C-15), ARB deleted the requirement in section 95111(b)(1)(A)10 that retail providers and marketers must specify purchases of substitute energy. ARB also deleted the definition of "substitute energy" at section 95102(a)(173) in its entirety and modified the definition of "specified source of power" at section 95102(a)(166) (now 95102(a)(180)) to include California-eligible renewable resources under contract to supply power. With those changes, retail providers will report the total amount of renewable power generated for the contract over the report year as from a specified source. It is not necessary to report power transactions related to firming power provided the amount of firming power and the excess deviation in renewable energy are net zero at the end of the year. We believe these modifications will have an effect similar to what the commenter was intending with the suggested addition of a new paragraph addressing intermittent renewable resources, and we determined the proposed language was not needed in addition to the modifications described in this paragraph. As noted in response to comment C-15, if ARB needs to have separate information about substitute power in its future emission control regulation, it will consider adding the requirement to the reporting regulation at that time.

C-17. Native Load Stipulation

Comment: Retail providers who make investments in facilities, either ownership or in a long term contract, with emissions rates lower than 1,100 lbs/MWh should be allowed to claim the energy from those facilities as serving native load, as long as the retail provider claims all of the energy from facilities owned or contracted with higher capacity factors. ARB should revise language in 95111(b)(3)(H). [PGE(13)]

Agency Response: ARB accepts this recommendation and has revised the criterion at section 95111(b)(3)(I)3. to require the facility to be "partially or fully owned by the retail provider, operated by the retail provider, or under a long term power contract. If a facility is designated as serving native load on this basis, all generating facilities from which the retail provider purchases or takes specified power that run at the same or greater average annual capacity factor shall also be designated as serving native load."

C-18. Retail Providers' Electricity Purchase Contracts Are Legitimate

Comment: There should be no presumption of illegitimacy for a retail provider's resource sales from out-of-state facilities or procurements from out-of-state low- and zero-GHG facilities. A contract that at the time it was made, had both sufficient consideration and a lawful object, is enforceable and should have a presumption of legitimacy. (Civil Code sections 1550, 1595, 1596, 1607, 1614, 1615; Evidence Code section 500.) There is no record evidence in ARB's rulemaking to support any conclusions of malfeasance when retail providers engage in wholesale sales from high-GHG facilities. Therefore, there is no evidence that would overcome the validity of a contract between consenting parties that has sufficient consideration (a market-based price in exchange for the delivery of energy that includes all environmental attributes) and a lawful object (the procurement of low- or zero-GHG resources for the purpose of reducing a utility's resource emissions). Furthermore, the legitimacy and lawfulness of this contract could hardly be suspect as a consequence of subsequent and unrelated acts of the non-California party. For instance, if at some point later the non-California party procures high-GHG resources to replace the low-GHG resources it lawfully sold to the California retail provider, this lawful subsequent act does not nullify the consideration or object of the original contract. The courts will not invalidate a contract unless its contravention of sound public policy is entirely plain and the burden is on the contract's opponent to show that a contract's enforcement would be in violation of settled public policy. (Rosen v. State Farm General Ins. Co., 30 Cal. 4th 1070, 1082 (2003); Moran v. Harris, 131 Cal. App. 3d 913, 920 (1982).) ARB should steer far from declaring that certain wholesale sales are "unacceptable" and that all wholesale sales exceeding 10 percent of an ownership share from out-of-state facilities come equipped with a presumption of impropriety. (Bovard v. Am. Horse Enters., 201 Cal. App. 3d 832, 839 (1988).) [CMUA(25)]

Agency Response: This comment was made as part of the commenter's recommendation that section 95111(b)(3)(O) be deleted in its entirety. See response to comment C-21 for ARB's reply to that recommendation and to the comment that ARB is attempting to regulate electricity sales that it has not authority over. Nothing in this regulation would render contracts of retail providers unenforceable or invalid, nor is ARB suggesting that any such contracts are illegitimate or the product of malfeasance. ARB will eventually decide, when it adopts emissions control regulations for the electricity sector, how to account for certain transactions in which retail providers serving California customers replace high-emissions electricity imports from coal plants they own with imports of electricity from other existing low-emissions sources. As noted elsewhere, this regulation merely collects certain information related to identifying such substitutions, but does not determine how they will be handled in a future regulatory program.

C-19. Emission Allocations for Exchange Agreements

Comment: All exported electricity should not be attributed to retail providers. Exchange agreements are an example where energy delivered to California is typically hydro but would be attributed the default factor by ARB methodology. The retail provider would be responsible for both the import and the export of the exchange agreement. [SCE(16), SCE(BH3), SCE(T13)]

Agency Response: The proposed regulation does require that electricity transferred under exchange agreements be reported as purchases and electricity delivered, as a wholesale sale. The attribution of emission responsibilities is not part of the regulation and will be determined when ARB develops emission reduction control regulations. For that reason, ARB cannot agree to modify the regulation to address attribution of electricity exports at this time. One option provided that is available in the proposed regulation is for asset owning or asset controlling suppliers to voluntarily report information and be assigned an emission factor specific to their fleet of power generating facilities. This option may enable retail providers to claim lower emission rates for their purchases under exchange agreements.

C-20. Power Exchanges Should not be Double Counted

Comment: LADWP recommends that energy exchanges and swaps be reported and handled as exchange transactions rather than a regular energy purchases and sales, to ensure the emissions are not double counted. [LADWP(BH6)]

Agency Response: ARB does not believe that this additional distinction is needed in the reporting regulation. The CPUC/CEC recommended that exchanges be treated as separate purchases and sales. ARB agrees that this approach is more accurate for emissions accounting. A related point is that ARB anticipates that emission calculations for purchases from hydroelectric energy suppliers will be based on supplier specific emission factors and not on a default emission factor.

C-21. ARB Cannot Restrict or Penalize Out-of-State Power Transactions

Comment: AB 32 does not give ARB authority to place restrictions on which out-of-state "sink" may be matched with each out-of-state source. Therefore, if a California retail provider procures low- or zero-GHG energy from an existing renewable facility, and pays to have it delivered to California, the GHG emissions from that generator are defined as statewide GHG emissions. AB 32 also does not authorize ARB to penalize retail providers for selling a higher-emission resource and replacing it with an existing lower-emission resource. Such a penalty would have the effect of impermissibly capping the GHG emissions of out-of-state sellers and out-of-state generation not consumed in California. Eventually, under whatever regulatory mechanism ARB selects to achieve emission reductions for the power sector, reporting entities should only be attributed with the actual emissions from electricity actually received to serve their load in California.

CMUA recommends deletion of section 95111(b)(3)(O) in its entirety as a more effective and less burdensome alternative. AB 32 does not proscribe wholesale sales from plants outside California. There is no evidence in the record to support a notion that certain wholesale sales are unacceptable based upon the seller's purpose. This concept was pejoratively labeled "contract shuffling" in the recommendation made by the Joint Agencies that is incorporated in Attachment C. The determination in D.07-09-017 that certain wholesale sales would not achieve real emission reductions was clearly erroneous and was not supported by any evidence adduced by the Joint Agencies. The Joint Agencies collected no substantial evidence to demonstrate that any type of wholesale sale would be more or less likely to comply with AB 32. CMUA is unaware of any activities undertaken by ARB to collect any evidence to support the necessity for these regulations. There was no discussion or explanation in the ISOR describing the need for regulations to distinguish between different reasons for a retail provider making wholesale sales. These concepts were briefly mentioned in non-regulatory Attachment C (Interim Emissions Attribution Methods for the Electricity Sector), but essentially by stating that the Joint Agencies "noted" that California retail providers could "potentially" modify contracts whereby emissions would remain unchanged. (e.g., Attachment C at C-8, C-9). [CMUA(25)]

Agency Response: ARB decided to revise rather than delete section 95111(b)(3)(O) (now numbered 95111(b)(3)(R)(1)). The revision gives California retail providers the option of reporting wholesale electricity sales from coal-fired power plants they own to buyers outside California under circumstances where the retail providers either did not need the electricity themselves or where congestion in the transmission system prevented them from taking the electricity. For retail providers that choose to report this information, ARB could consider the information if it adopts in the future an electricity sector emissions reduction program that attributes a particular emissions factor to electricity that retail providers purchase in lieu of taking electricity from generating plants they own. ARB believed the reporting of this information should be allowed as an option because consideration of the information could work to the advantage of retail providers, depending on the form of future emissions control measures that are eventually adopted by ARB.

Nothing in this regulation restricts or proscribes the sale or transmission of electricity from any source to any load or "sink," nor does the regulation penalize retail providers for their decisions to sell electricity associated with higher emissions outside California in order to import into California electricity associated with lower emissions. If ARB eventually adopts an electricity sector emissions control program that the commenter believes will penalize retail providers unfairly, this objection can be asserted in regard to the future regulation. To the extent this comment is based on Attachment C to the Staff Report, which contains emission attributions derived from last year's recommendations of the California Energy Commission and Public Utilities Commission, that document is not part of the regulation. Any such attributions will be revisited and in all likelihood changed prior to adoption of emission attributions in a future rulemaking. See response to comment C-41 for further discussion of Attachment C. See response to comment A-10 for further discussion about why ARB disagrees that the definition of "statewide greenhouse gas emissions" deprives it of authority to gather information about the sale of electricity from high-emissions electricity plants that California retail providers own in other states, and why this information is important to accomplishing the purposes of AB 32. See response to comments C-42 and C-55 for a discussion of the CEC and CPUC recommendations and the basis for ARB's decision to gather certain information that is relevant to identifying possible "contract shuffling" by retail providers.

C-22. Provisions Relating To Out-of-State Electricity Transactions Are Arbitrary and Capricious

Comment: ARB has no authority to implement regulations based upon erroneous interpretations of AB 32 by proposing arbitrary and capricious rules that have no rational basis. This unlawfully blurs the line distinguishing between activities that are lawful and beneficial as opposed to any heretofore undefined activities designed by retail providers to purposely circumvent AB 32. [CMUA(25)]

Agency Response: This comment refers to provisions that require California retail providers to report certain information about ownership share in high-emission power plants, and to requirements in the originally proposed regulation (which are now optional) that certain wholesale sales and reductions in electricity production relating to those plants be reported, even if they do not relate directly to power imported into California. See responses to comments A-10, A-20, C-21, C-60 for an explanation of why ARB has authority to adopt these provisions and how they are consistent with and necessary to achieve the purposes of AB 32. This regulation does not prohibit any electricity transactions or make them unlawful, but is rather designed to collect information that may be needed to support a future regulation to reduce GHG emissions from electricity sector sources and to gauge progress towards the 2020 emissions reduction goal.

C-23. Assigning 7.5% Transmission Loss to Imports

Comment: ARB should not apply a 7.5% transmission loss factor to all imports from the Pacific Northwest, Southwest and unknown regions. [SCE(16), SCE(BH3), SCE(T13)]

Agency Response: The attribution of emissions to imported power is not part of the proposed regulation. The California Energy Commission (CEC) has recommended that default emission factors be revisited regularly, including the 7.5% transmission loss factor. ARB expects to revisit these emission factors prior to any assignment of emissions to imports

C-24. Calculating Ownership Share Differential

Comment: ARB needs to clarify how to calculate and report ownership share differential for out-of-state facilities. [SCE(16)]

Agency Response: ARB decided to remove the requirement for retail providers to calculate and report an adjusted ownership share differential. Reporting requirements related to this calculation may be revisited as ARB develops an emissions reduction control regulation. In the meantime, retail providers are required to report their ownership share and power taken from owned or partially owned facilities. Additional information on wholesale sales made from out-of-state facilities to out-of-state clients may be provided voluntarily.

C-25. Emission Factor for Unspecified Wholesale Sales Inappropriately Used

Comment: Use of the emission factor for unspecified wholesale sales (EFUWS) with the adjusted ownership share differential in Attachment C (at C-11) is inappropriate because it does not bear a relation to the adjusted ownership share differential, does not support the purpose of AB 32, and is arbitrary. The calculation for EFUWS has no relation to the adjusted ownership share differential. The adjusted ownership share differential calculation is intended to penalize a retail provider for selling power from an owned plant to avoid the attribution of the emissions. This penalty is significantly impacted by the EFUWS calculation. The EFUWS calculation is based upon unspecified sales. This factor is then multiplied by the amount of power attributed to the retail provider in the adjusted ownership share differential calculation. However, the adjusted ownership share differential does not differentiate sales based on whether they are specified or unspecified. It is strange then to use an emission factor based on only unspecified sales from in-state generation to determine a penalty for out-of-state generation. There is no evidence in the record to support using the EFUWS to calculate the adjusted ownership share differential penalty, and to do so is both arbitrary and illogical. Use of EFUWS does not support the purpose of AB 32. It serves as a multiplier to determine a penalty for sales from owned plants for "unacceptable" purposes. The primary "unacceptable" purpose is to reduce emissions attributed to the retail provider. However, because of the variables used to arrive at this number, the EFUWS does not bear a clear relation to the level of GHGs actually emitted by a retail provider. The EFUWS is based on the emission factor of the resources a retail provider uses for sales to unspecified sources. The percentage of sales that a retail provider makes that are unspecified may be very small or large. The calculation does not take into account how large a percentage of a retail provider's sales are unspecified. Therefore, it is possible for a retail provider with an overall mix of resources that, in the aggregate, are low-GHG emitting, to be penalized severely if only a small percentage of its sales are unspecified and it uses high-GHG emitting resources to make these sales. The opposite is also true. A retail provider with a resource mix that is made up of mostly high-GHG emitting resources would receive only a minor penalty, so long as it has a smaller percentage of unspecified sales. Penalizing a retail provider based on the percentage of unspecified sales does not bear any reasonable relation to the goals of AB 32. No evidence in the record establishes that unspecified sales are in any way connected with increased GHG emissions. The fact that different retail providers could have widely different EFUWS calculations, with the only differing variable being the percentage of sales that are unspecified, means that this calculation is arbitrary. Nothing in AB 32 or in the record supports penalizing a retail provider based on its unspecified sales. [CMUA(25)]

Agency Response: All references in the regulation to "ownership share differential" and "adjusted ownership share differential," including the formulas for calculating those values, were removed from the regulation, as described in responses to comments A-10 and C-60. Attachment C to the Staff Report, including the emissions attributions relevant to this comment, is not part of the regulation. ARB recognizes that changes will likely be needed in the formulas contained in Attachment C prior to any future use in an emissions control program. Any such future use would occur only following an additional regulatory process that will allow a full public review of proposed emission factors for unspecified wholesale sales. See responses to comments C-21 and C-41.

C-26. Clarify WAPA Requirements

Comment: ARB should clarify language regarding the Western Area Power Administration (WAPA) reporting requirements. [SCE(16)]

Agency Response: ARB has added the recommended clarifications to section 95111(b)(1)(F) to stipulate that WAPA reports transactions related to serving WAPA's end-use California customers.

C-27. Default Emission Factors for New Contracts with Large Hydroelectric and Nuclear Electric Generating Facilities

Comment: ARB adopts the joint recommendation of the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) to assign a default CO_2 emission rate developed for "unspecified" generation sources. ARB explains that this recommendation is intended to minimize "contract shuffling" which could occur if a retail provider purchased less generation from a high GHG plant, diverted the dirty power to areas where no GHG restrictions exist, and replaced that energy with clean energy from large hydroelectric generation or nuclear power. ARB's recommendation is contrary to the intent and requirements of AB 32 and it is inappropriate to require reporting to implement this proposal. [SWC(27)] In apparent response to the Joint Recommendations, ARB has proposed that the ARB adopt regulations that would require retail providers to separately identify their energy purchases made under new contracts with large hydroelectric generating facilities over 30 megawatts (MW) and nuclear generation, so that ARB can assign a default emission factor of 1,100 lbs CO_2 per electricity megawatt-hour (MWh) to them… The proposed adoption and assignment of such an arbitrary emission factor, when actual emissions are known to be virtually zero, may conflict with California's Administrative Procedures Act… Metropolitan recommends that the ARB reject inclusion of section 95111(b)(3)(F)(1)-(2) of ARB's proposed regulation, which would remove the requirement for specialized reporting of large hydropower purchases to which a default emissions factor would be assigned. [MWD(40)] The LADWP recommends 95111(b)(3)(F) of the regulations and section 4.1.1 of the proposed interim emission attribution methods be deleted. [LADWP(BH6)]

Agency Response: ARB has retained the CPUC/CEC recommendation here, mindful of the concern that future reductions be real. However, the requirement cited by the commenters (now specified in 95111(b)(3)(H)) is at this time only for purposes of collecting information, not for assigning emissions responsibility. ARB remains committed to collecting public input prior to use of the information in any future emissions control regulation. The interim emission attribution methods (Attachment C to the staff report) were provided for discussion purposes only and are not regulatory. Attribution methods will be established in the context of designing future emission reduction regulations. See response to comment C-28 for further discussion of these issues.

C-28. Treatment of Large Hydropower and Nuclear Power

Comment: The proposed regulation (at section 95111(b)(3)(F)) lacks authority and no California constitutional or statutory provision expressly or impliedly permits or obligates the ARB to adopt this regulation. Determining that the proposed regulation is reasonably necessary to effectuate the purpose of the statute is not supported by substantial evidence. The proposed regulation is inconsistent with the statutory objectives of AB 32. CMUA recommends deletion of the subsection as a more effective and less burdensome alternative.

This proposed regulation contradicts the express requirements of AB 32 for accuracy. ARB may not supplant actual, known emissions with a default, especially when the facility is a zero-emission source. AB 32 requires ARB to develop regulations that "[e]nsure rigorous and consistent accounting of emissions…" (Health & Safety Code section 38530(b)(4).) The proposed regulations should be deleted since, in conjunction with the non-regulatory Attachment C, they knowingly and expressly assign an incorrect emission rate to verifiably clean resources. The proposed regulation is inconsistent with the AB 32 requirements for the emission limit determination, which AB 32 requires to be "the most accurate determination feasible …." (Health & Safety Code section 38550.) The accuracy of the limit is critical since it shall "be used to maintain and continue reductions in emissions…" (Health & Safety Code section 38551(b).) [CMUA(25)]

Agency Response: This comment is focused on section 95111(b)(3)(F), which in its original form required California retail providers to report whether electricity purchased from large hydroelectric and nuclear facilities was obtained under a contract in effect prior to 2008. The provision now appears at section 95111(b)(3)(H), and has been expanded to include additional reporting categories for purchases of electricity from large hydroelectric and nuclear plants. See response to comment C-27, which requested deletion of the same provision, and response to comment C-41 on the non-regulatory nature of Attachment C. This regulation does not require the use of an artificial emission attribution as stated in the comment; whether to include such a requirement would be decided by ARB at the time it adopts a subsequent regulation for control of GHG emissions. The requirement at Health & Safety Code section 38530(b)(4) that the reporting regulation ensure a "rigorous and consistent accounting of emissions" supports rather than undermines ARB's collection of information about the circumstances regarding the purchase and importation of electricity, since collection of information of potential relevance to a emissions control program that has yet to be designed is both more rigorous and consistent than failing to collect information that may ultimately be necessary. Health & Safety Code sections 38550 and 38551(b) are not directly relevant to this issue because they concern the 2020 GHG emissions limit and not the reporting regulation. But in any case, ARB disagrees that collection of this information makes GHG emissions data any less accurate, given the fact no substantive emissions controls have yet been decided upon, and given the fact that the level of accuracy of emissions data is affected in part by whether reported reductions in emissions are "real, permanent, quantifiable, verifiable, and enforceable," as required by Health & Safety Code section 38562(d)(1). See response to comment A-10 for further discussion.

C-29. Power Exported Out-Of-State Directly from Facilities

Comment: How does Sierra comply with 95111(a)(1)(K), which requires reporting of all energy sales from facilities it operates and exports "directly out-of-state"? Sierra has the same question with respect to 95111(a)(2)(D). [SP(43)]

Agency Response: ARB has added language to sections 95111(a)(1)(K) and 95111(a)(2)(D) to clarify that these sections only apply to facilities and power units located inside California. Thus, Sierra would report information under these sections only for facilities/units located inside California that are operated by Sierra.

C-30. Statutory Requirement That Emission Reductions Be "Real" Does Not Give ARB Authority To Require Reporting Of Activities Beyond "Statewide Greenhouse Gas Emissions"

Comment: The regulations ensuring the achievement of real reductions apply to statewide GHG emissions only, as that term is expressly defined in Health & Safety Code section 38505(m). AB 32 must be "harmonized by considering each particular clause and section in the context of the statutory framework as a whole." (Moyer v. Workers' Comp. Appeals Bd., 10 Cal. 3d 222, 230-231 (1973). The definition of a "real" emission reduction must necessarily be interpreted as a reduction in statewide greenhouse gas emissions. The definition of "real" cannot be expanded to require a California retail provider to reduce emissions outside the scope of AB 32. The Joint Agency recommendation in D.07-09-017 errs in its interpretation of real reductions by expanding the geographic scope of AB 32 to include emissions that have no connection with California. Pursuant to AB 32, a "real" reduction of statewide GHG emissions will actually occur if a retail provider reduces its "total annual emissions of greenhouse gases *in the state*, including all emissions of greenhouse gases from the generation of electricity *delivered to and consumed in California*, accounting for transmission and distribution line losses, whether the electricity is generated in state or imported." (Health & Safety Code section 38530(b)(2) (emphasis added).) The definition of "real" is necessarily limited to the jurisdictional scope of AB 32. As a necessary component of this, the reporting mechanism should be designed to prevent retail providers from falsely claiming that electricity consumed in California is coming from a designated resource when actually it is not. On the other hand, the reporting mechanism must also recognize legitimate and lawful business practices that pertain to the sale or purchase of electricity. [CMUA(25)]

Agency Response: ARB disagrees with the assertion that Health & Safety Code section 38505(m)'s requirement that emissions reductions be "real, permanent, quantifiable, verifiable, and enforceable" fails to support ARB's authority to collect information about certain out-of-state business activities of California retail providers. The information at issue is either directly relevant to statewide greenhouse gas emissions, as defined in AB 32, or relevant as to whether reported reductions in statewide greenhouse gas emissions are real, which is one of the standards that Health & Safety Code section 38562(d)(1) instructs ARB to ensure. Although the commenter endorses the principle of statutory construction requiring that all parts of the statute be harmonized, the commenter proceeds to offer an interpretation of the statute that elevates the definition of "statewide greenhouse gas emissions" as the only sentence to be given weight in determining "the jurisdictional scope of AB 32," with the result that the statutory requirement that reductions be "real" is reduced to surplusage.

ARB also disagrees that the proposed regulation, as originally proposed or as modified, requires the reporting of emissions "that have no connection with California." Out-of-state emissions and transactions were included in the regulation's reporting requirements or optional reporting only if they involved emissions or wholesale sales from generating facilities that are owned or operated by California retail providers. They also are related to California in that they either serve loads in California – in which case they clearly are statewide greenhouse gas emissions under AB 32 – or they relate to transactions that may involve "contract shuffling" to reduce reported emissions without achieving any real reductions in actual emissions. In either case, there is a substantial relationship to California.

C-31. Duplicate Reporting of Power Transactions by Multi-Jurisdictional Retail Providers

Comment: How does Sierra report energy purchased from its California qualified facilities to serve both Nevada and California customers in order to comply with Section 95111(b)(2)(D)'s requirement to report "power exported from specified sources inside California?" Is this purchase an export because it is used to satisfy Nevada load, even though it also serves California customers? A similar section (95111(b)(3)(E)) requires SPPC to report the same purchase as "power purchased or taken from an in-state specified source." [SP(43)]

Agency Response: ARB has revised the regulation language to eliminate the reporting duplications identified by the commenter. The revisions exempt multi-jurisdictional retail providers from reporting imports and exports under sections 95111(b)(2)(B)-(F). Multi-jurisdictional retail providers will report instead under sections 95111(b)(3)(E)-(F) for wholesale purchases originating inside California and under 95111(b)(3)(G), a new section, for all other purchases.

C-32. Reporting Exports by Multi-Jurisdictional Retail Providers

Comment: SPPC generates, purchases and sells energy outside California. Does it make sense to label all these sales as "exports" with the exception of wholesale sales to purchasers who inform SPPC that they plan to deliver that energy into California? (95111(b)(3)(I). [SP(43)]

Agency Response: To address the issue raised in the comment, section 95111(b)(3)(I) has been revised and is now numbered 95111(b)(3)(J). The new section exempts multi-jurisdictional retail providers from reporting wholesale sales not delivered to California as exports. ARB added section 95111(b)(3)(O) that specifies how multi-jurisdictional retail providers are to report wholesale sales that are not delivered to California.

C-33. Multi-Jurisdictional Retail Providers Reporting Burden

Comment: SPPC is required to report on 100% of its Nevada operations even though only 6% of its power is used by California customers. This reporting obligation is potentially burdensome. [SP(43)]

Agency Response: The CPUC and the CEC jointly recommended that ARB include multi-jurisdictional retail providers in the reporting regulation. The commissions further recommended that ARB determine California emissions from these retail providers by pro-rating total emissions for their service territories based on the portion of total retail sales sold to California. ARB elected to follow these recommendations at least until an emissions control program is designed, which may affect what information needs to be collected. In order to calculate total emissions for multi-jurisdictional retail providers for inventory purposes or for a possible future trading scheme, ARB must collect the information from multi-jurisdictional retail providers that parallels the information collected from California retail providers. In the future, if ARB selects a first seller or source based point of regulation for a trading scheme or does not choose to implement a trading scheme, ARB will revisit the reporting requirements for all retail providers and eliminate reporting of information that is not needed.

C-34. Use of CCAR Reports for GHG Reporting Under AB 32

Comment: ARB has chosen not to accept a Retail Seller's CARROT report to The California Climate Action Registry (CCAR), or as the case may be The Registry, as Sierra Pacific Power Company (SPPC) expected pursuant to Health & Safety Code section 38530. SPPC's concern is that ARB's regulation could conflict with a new Nevada law and proposed regulation requiring Sierra to report its greenhouse gas emissions to CCAR, potentially leading to jurisdictional conflicts with the State of Nevada. ARB has decided to do this despite AB 32's requirement that entities that voluntarily participated in the California Climate Action Registry prior to December 31, 2006, and have developed a greenhouse gas reporting program, shall not be required to significantly alter their reporting or verification program except as necessary to ensure that reporting is complete and verifiable for the purposes of compliance with this division as determined by the state board. (Health & Safety Code section 38530(b)(3).) ARB has made no finding that an alternative non-CCAR reporting program is necessary to ensure that Sierra's reporting is complete and verifiable for the purposes of accounting for GHG emissions from all electricity consumed in California. (H&S Code section 38530(b)(2) and (b)(3).) SPPC voluntarily joined CCAR and made its initial report to CCAR in 2007 in reliance upon assurances placed in the statute that it would not be required to significantly alter its reporting and verification program to CCAR. SPPC's initial concern is that ARB's reporting regulation may conflict with or duplicate the voluntary reporting requirements presently in effect through CCAR. However, irrespective of whether the ARB has made the necessary finding that rejection of CCAR reports is necessary to ensure Sierra's reporting is complete and verifiable, Sierra is also concerned that duplicative reporting would be an additional expense that would impose a needless and unreasonably burdensome cost on its California customers. [SP(43)]

Agency Response: Health & Safety Code section 38530(b)(3) requires ARB to incorporate the standards and protocols of CCAR in its reporting regulation "[w]here appropriate and to the extent feasible." The statute also states that entities that have voluntarily participated in CCAR prior to December 31, 2006 and have developed a GHG emission reporting program "shall not be required to significantly alter their reporting or verification program except as necessary to ensure that reporting is complete and verifiable for the purposes of compliance with this division as determined by the state board."

ARB's development of the regulation was consistent with these directives from the Legislature, and included close work with CCAR representatives. Core requirements of the regulation drew from CCAR *standards*, such as independent third party verification, while CCAR *protocols* provided the foundation for our reporting methodologies. Some differences between the ARB regulation and the CCAR program were also necessary, due to (1) other requirements of the Act and California regulatory law, (2) the need to develop new methodologies for sources not specifically considered by CCAR protocols, and (3) agency recommendations and public comment. For example, Health & Safety Code section 38530(b)(2) requires the mandatory reporting program to "account for all greenhouse gas emissions from all electricity consumed in the state, including transmission and distribution line losses from electricity generated within the state or imported from outside the state." The CCAR Power and Utilities Protocol handles imports through use of factors that provide only a rough approximation of emissions. For this and other reasons the Protocol is undergoing revision through The Climate Registry. Also, some sources of high emissions consequence, such as oil refineries, were not addressed through CCAR protocols, making necessary the development of additional methodologies.

In addition, the California Pubic Utilities Commission (CPUC) and the California Energy Commission (CEC) provided ARB with joint recommendations on the information they believed should be reported to ARB from electricity retail providers and marketers. The recommendations included extensive description of various kinds of power transaction information on imports, exports, and transactions inside California that would be needed in the development and implementation of future regulations such as a trading scheme. ARB considered these recommendations and agreed that all information should be gathered pertinent to future actions. For this reason the reporting of power transactions goes well beyond the scope of the CCAR protocol for the electricity sector.

Furthermore, ARB determined that a certain level of uniformity and consistency was necessary for effective and equitable reporting of statewide greenhouse gas emissions across industrial sectors to effectively serve regulatory and potential market programs. ARB determined that this need limited its ability to incorporate all CCAR reporting and verification requirements as observed by individual CCAR members. In some cases ARB chose more accurate methods from among several alternatives available to CCAR members, in order to ensure the regulation would meet the requirement of Health & Safety Code section 38530(b)(4) for "rigorous and consistent accounting of emissions." CCAR representatives informed ARB that they were aware that CCAR standards and protocols, developed for voluntary reporting, were not entirely appropriate for a mandatory reporting program in California. CCAR staff also indicated that CCAR standards and protocols would likely be amended to conform more closely to the ARB reporting regulation.

The reasons for ARB's decision to depart from CCAR's protocols, standards, and programs is reflected in the rulemaking record and was discussed with regulated industries during workshops on the regulation. When ARB approved he regulation, the Board's findings included the following:

> The proposed regulations, to the maximum extent feasible and appropriate, incorporate the standards and protocols developed by the California Climate Action Registry;
>
> The proposed regulations include reporting requirements beyond those currently utilized by the California Climate Action Registry for voluntary emissions reporting; these regulatory requirements are necessary for the ARB's mandatory reporting regulations to ensure that reporting is complete and verifiable for the purposes of compliance with AB 32; …

The Board's resolution also noted that "ARB staff worked closely with staff of the California Climate Action Registry (CCAR) who provided invaluable technical assistance and helped to ensure consistency, to the maximum extent feasible, between the voluntary CCAR reporting program and the proposed mandatory GHG reporting regulations." CCAR staff testified to this cooperation and in support of the proposed regulation at the December Board hearing.

C-35. Regulation Is At Odds With New Reporting Requirements of Nevada

Comment: SPPC is now under new mandatory reporting obligations for GHG emissions in Nevada. Pursuant to Nevada Senate Bill ("NSB") 422, Sierra will be required to report annually the GHG emissions from all electric generating units of five MWs or more to a registry to account for verified GHG emissions on an on-going basis. (Draft regulations were pending in Nevada at the time the comments were submitted.) Except for 20 MW from a renewable power qualifying facility in California, all California customers of SPPC are served from generating facilities in Nevada. Most of this generating capacity is internal to Sierra, with a significant portion purchased from third parties. However, with the addition of new generation capacity in June 2008, Sierra plans to supply most of its system from self-owned generating facilities located in Nevada. It will be required to report all of these sources to the Nevada State Environmental Commission pursuant to NSB 422; and coincidentally report on all of the same sources, over which it has operational control, to the ARB. The reporting of emissions of the former will be accomplished through CCAR reporting protocols, and for the latter through the Proposed Regulation. The only apparent difference in the scope of the reporting obligations is that under NSB 422, there is a de minimis reporting threshold for units of 5 MWs or more; whereas under the Proposed Regulation the threshold is only 1 MW. However, Sierra plans to submit a complete inventory of its GHG emissions pursuant to CCAR protocols, irrespective of the 5 MW threshold. CCAR's CARROT protocols are complete (and verifiable) and potentially even more complete than the Proposed Regulation since it will include all GHG emissions from resources used to serve California customers, regardless of Sierra's operational control.
Though the scope of the reporting obligations to Nevada and California are essentially duplicative, the emissions inventories reported to the two states are potentially different because the reporting protocols will be different. Sierra is concerned that different reporting protocols could result in different inventories of the same actual GHG emissions. This situation obviously could lead to confusion and could challenge the integrity of Sierra's inventory, cap and allowance allocation in any prospective California cap-and-trade scheme or regional cap-and-trade system. Moreover, ARB's Proposed Regulation would place an arm of the State of California in the position of calculating a potentially different inventory of GHG emissions from electric power generation in Nevada from that calculated by an agency of the Nevada state government. At best, this presents a potentially awkward situation; at worse, it presents a source of friction with the State of Nevada. Additionally, there exists at present a sensitivity in neighboring states to the broad, and potentially extraterritorial, reach of California legislation outside its borders, particularly with respect to this issue. The current draft of ARB's reporting regulation could potentially exacerbate the situation.

A simple and practicable way for the ARB to avoid these complications would be to accept the mandatory reports on GHG emissions that Sierra will submit to Nevada. This approach would be both reliable and defensible from ARB's perspective. Since Sierra's reports will be mandated under Nevada law, ARB is assured that the data will be prepared subject to regulatory oversight. Also, since

Sierra will follow CCAR protocols, which ARB is actually required to accept in the absence of a finding that the protocols are incomplete or unverifiable, which they are not, the California Legislature has mandated the use of this reporting method for Sierra's compliance with AB 32. In short, ARB can acquire all the information it needs to calculate California's pro rata share of Sierra's GHG emissions through SPPC reporting to the NSEC through CCAR but with much less effort and cost than under the Proposed Regulation. A model for such an approach can be found in the CPUC's D.07-01-039 ("Interim Decision on Phase 1 Issues: Greenhouse Gas Emissions Performance Standard", January 25, 2007), where the CPUC granted to Sierra and PacifiCorp an alternative compliance mechanism conditioned upon obligations to disclose GHG emissions to another state's regulatory commission. A similar rule based upon the additional disclosure requirements of NSB 422 would be consistent with existing CPUC policy and would fulfill the intent of AB 32. [SP(43)]

Agency Response: In response to comments received, several changes were made to the reporting requirements in sections 95111(b) and (c) for multi-jurisdictional retail providers. Some of these changes are specifically described in responses to comments C-29, C-31 and C-32. These changes demonstrate that ARB has been willing to modify the regulation to address special situations faced by multi-jurisdictional retail providers. But ARB determined it would not make the change recommended by the commenter for acceptance of reports prepared for the State of Nevada and CCAR because to do so would leave ARB with inadequate and inconsistent information. Though we appreciate the commenter's recommendation to examine an alternate compliance mechanism of the sort CPUC has provided to multijurisdictional retail providers in the past, the CPUC and CEC have in this case formally recommended that ARB collect all information needed to calculate load-based emissions for multi-jurisdictional retail providers, because load-based calculations based on all facility emissions as well as power purchases and sales may be the best basis to determine California emissions for multi-jurisdictional retail providers in a future cap and trade program. ARB does not believe it is unduly inconsistent or awkward that two states use somewhat different methods of calculating and reporting emissions, or that those differences might result in some variation in the resulting emissions values that are reported to the respective states. In fact, these variations are to be expected given differences in the statutes that each state is implementing. Finally, this comment does not accurately describe the Legislature's direction to ARB regarding use of CCAR protocols and standards, and reporting and verification programs developed under them. See response to comment C-34.

C-36. Inability to Reduce Carbon Footprint
Comment: The proposed regulation lacks flexibility to count emissions in proportion to carbon-free or low carbon energy destined for California customers or permit SPCC to reduce its reporting obligations should it reduce its carbon footprint in California. SPPC is concerned that a fixed apportionment based on retail load is not flexible enough to allocate GHG emissions to California load

under the likely scenario of a cap-and-trade system with emissions allocated to load. For example, Sierra has a renewables portfolio standard (“RPS”) obligation in California that differs temporally from its RPS obligation in Nevada. The respective state RPS obligations operate under different timetables. To comply with its California obligation Sierra has two choices: either accelerate procurement of renewable energy across its entire system so the California piece can also meet the California RPS, or accelerate the California territory only. However, Sierra has one, integrated system and only one control area for both states. Thus, it cannot dispatch renewable energy solely for California. Thus, the only way that Sierra can meet California’s accelerated RPS schedule for California alone is to allocate a portion of its renewable procurement to California on a different basis than pro rata, retail sales. Indeed, Sierra has submitted its plan to the CPUC to procure a new renewable energy facility and dedicate a portion of that power especially for California.

Under the regulation as proposed, Sierra would not be able to perform a similar allocation with respect to a facility with lower GHG emissions than its system average in order to meet a California cap. The current scheme would not allow Sierra to procure carbon-free energy for California because it fixes an allocation of Sierra’s system-wide carbon emissions using a single formula of the ratio of California retail sales to total system sales. Consequently, the only avenues open to Sierra for reducing its pro rata share of “California” emissions would be either 1) to reduce GHG emissions for Sierra’s system as a whole (virtually all of which occur in Nevada and 94 percent of which are due to Nevada load); or 2) to procure allowances to reduce its “California” inventory to meet the California cap. Sierra contends that the former approach unreasonably interferes with existing law and regulation of Sierra’s Nevada operations. Sierra also believes that the latter approach would place its California ratepayers at a disadvantage since they could not take full advantage of a cap-and-trade scheme, as their only method of compliance would be to purchase allowances.

Additionally, even if SPPC were inclined to follow California law over Nevada law and reduce its GHG emissions for its system as a whole, it might not be allowed to do so by the PUCN, nor is it likely that the PUCN would allocate the costs to Nevada ratepayers for reducing Nevada emissions to meet California requirements. Thus, the only avenue remaining to SPPC would be to assign all costs for reducing GHG emissions across Sierra’s system to California ratepayers. Needless to say, such a disproportionate allocation of costs is unlikely to be permitted by the CPUC.

Consequently, Sierra is requesting that the proposed reporting regulation be amended to provide for greater flexibility than an allocation based upon the proportion of load of California customers relative to Sierra’s system as a whole. Such a change would allow Sierra to allocate or earmark specific zero emission renewable or clean energy procurements to California to meet AB 32 requirements along with RPS requirements. [SP(43)]

Agency Response: The proposed reporting regulation does allow retail providers to voluntarily report specially designed renewable energy programs for retail customers under section 95111(b)(3)(D). ARB does not believe it is appropriate to adjust reporting requirements for individual retail providers based on their reduced emissions in California, since rigorous and uniform reporting is necessary to obtain accurate information about emissions. It does not establish regulated emission responsibilities for individual retail providers. The commenter will have opportunity to participate in the development and design of future regulations and to voice its concerns. At that time, ARB will make every effort to insure that all regulated entities are treated equitably. The assignment of emission reduction responsibilities and emissions allocations would be part of future emission reduction regulations and will be discussed in separate public processes. For now, the mandatory reporting regulation is focused on gathering information that may be needed in future regulations. It does not dictate how the information will be used in future regulations or how allocations will be made if ARB implements a cap and trade program.

C-37. Source Specific Emission Factors for Fugitive CO_2 from Geothermal Facilities
Comment: A one tiered approach for the approval of the testing plans and approval of the emission factor would be more effective than a two tiered approach of having both the local Air Pollution Control District and the Air Resources Board approve the factors. Having a two tiered approval process will be burdensome and time consuming and will likely not be completed by the time we need to start collecting data in January 2008. [Calpine(24)]

Agency Response: ARB edited section 95111(i)(2) to clarify use of site-specific emission factors for geothermal generating facilities. ARB expects to approve test plans in consultation with air districts, and to approve the first emission factors developed under those procedures. Tests can thereafter take place under either air district or ARB supervision. In approving emission factors developed under the first source test, ARB also has the discretion to approve in advance emission factors developed under subsequent tests that follow the same protocol, and to leave the test supervision to the local air district.

With respect to timing, because operators have discretion in the choice of “best available” data and methods to apply in 2009 emissions data reports, approval of emission factors by ARB is not required for calculation of 2008 emissions. Emission factor derivation would be subject to review by the verification team where operators choose to verify 2009 reports. Operators must request ARB approval of test plans and measured emission factors to be used in 2010 emission reports.

C-38. Use of Source Test Terminology for Geothermal Facilities
Comment: Source testing assumes that certain procedures for stack testing will be followed. The testing conducted to determine site specific emission factors for geothermal may or may not be conducted at a stack and be source testing.

Some of the testing conducted to determine the site specific factors may be conducted in a pipe and may not be considered source testing although is very effective in determining a site specific factor. [Calpine(24)]

Agency Response: ARB understands that testing for CO2 in geothermal emissions may not involve a traditional source test, and has addressed this concern by editing the language in section 95111(i)(2) to remove the word "source" where it occurred before the word "test."

C-39. Default Emission Factor for Geothermal Will Overestimate Emissions
Comment: The emission factor used in the section 95111(i) equation for computing CO_2 emissions from geothermal power generating facilities will result in unrealistically high CO_2 estimates that do not accurately reflect actual emissions levels. [NCPA(BH2)]

Agency Response: We recognize that there can be substantial variability in the CO_2 emissions from geothermal generating facilities, and this variability is not reflected in a single average emission factor. As a default, we allow facility operators to use the ARB supplied emission factor, which is the same factor used by the federal government in calculating CO_2 emissions from geothermal generating facilities source. ARB does not support reducing the default factor because that would likely result in under-reporting actual emissions at certain facilities. Geothermal operators are also provided the option to calculate their CO_2 emissions based on direct testing performed at the reporting facility. This testing must be done with the oversight of the ARB or air districts, and the derived emission factors must be approved by the ARB (95111(i)(2)). We believe that this element of the regulation addresses the concern regarding potentially inaccurate CO_2 estimates for geothermal facilities.

C-40. Negative Consequences from Attachment C
Comment: Although the Supplemental Materials are not part of the proposed regulatory language the content of Attachment C in particular will likely have unintended negative consequences for DWR's SWP power portfolio and SWP operations immediately as well as in the future, as DWR attempts to negotiate long and short term power contracts with counterparties who are directly or indirectly subject to Assembly Bill 32's reporting, counting, and emissions reductions requirements. [DWR(37)]

Agency Response: It is correct that Attachment C to the Staff Report is not part of the regulation. The CPUC and CEC recommended that ARB collect certain information related to hydroelectric transactions, and the reporting regulation does this. Although the CPUC and CEC also recommended how ARB should assign emissions to these transactions, ARB has modified and retained these recommendations outside the regulation for future consideration, without Board endorsement or approval. In the course of adopting and implementing the Scoping Plan, ARB and its staff will discuss in open forums whether to implement a trading scheme, what the point of regulation should be, and how electricity transactions should be assigned emissions. ARB will revise reporting requirements and revisit the emissions attribution methodologies as soon as decisions are made that clarify what information and methodologies are needed.

C-41. Nature of Attachment C

Comment: ARB has expressly stated that the emissions calculations included in Attachment C are interim and non-regulatory guidelines. The commenter understands that ARB affirms the interim scope of these regulations and also that the actual ARB process for setting emission obligations has yet to begin. Despite the non-regulatory nature of Attachment C to the Staff Report, the commenter is concerned because the proposed regulation includes a requirement that retail providers report wholesale sales from out-of-state generating sources to out-of-state sinks and Attachment C includes calculations attributing emissions to the retail provider for those same out-of-state wholesale sales. By design, the adjusted ownership share differential is a calculation to determine a retail provider's penalty for certain power transactions that don't involve "acceptable" wholesale sales (see section 95111(b)(3)(O), Attachment C at C-8, C-9). Information required in the proposed reporting regulations is there primarily for the purpose of a penalty calculation based on the adjusted ownership share differential. It is not clear why this information is required since these sales do not involve statewide greenhouse gas emissions. Comments on calculations contained in Attachment C are being submitted as if the calculations were proposed as regulations because Attachment C may be a portent for future regulations. [CMUA(25)]

Agency Response: Attachment 3 of the Staff Report contains emission attributions derived from CEC and CPUC recommendations to ARB. This material was included in the Staff Report for informational and discussion purposes only and is not regulatory. Attribution methods will be established in the context of designing future emission reduction regulations. See response to comment A-10 for an explanation of how ARB modified the regulation to make voluntary the reporting of wholesale transactions from a power plant owned by a California retail provider to out-of-state buyers. See response to comment A-10 for a discussion of why ARB believes it can collect this information, and response to comment and C-21 for ARB's response to the concern that ARB is penalizing certain types of transactions.

C-42. CEC and CPUC Recommendations Not Binding on ARB

Comment: ARB is not obligated to follow interpretations of the Energy Commission and Public Utilities Commission if the interpretations are clearly erroneous. Furthermore, in this case, the recommendations from these commissions carry virtually no weight since they are not quasi-legislative rules. Even more, AB 32 does not require or request ARB to consider recommendations from the commissions in regard to mandatory reporting issues.

The under girding of the commissions' recommendation is a clearly erroneous interpretation of AB 32. The commissions state their belief that certain wholesale sales do not result in "real" reductions as required by AB 32. That belief, however, depends upon enlarging the scope of AB 32 authority to encompass the "atmosphere" anywhere in the world without geographic limitation. Neither of the commissions has been charged with developing the reporting regulations for AB 32 compliance and neither can make the claim of having special expertise in the reporting of air emissions. Hence, the commissions' interpretation merits virtually no weight. In this case, moreover, the interpretation was conceived without adequate consideration. At no point in their report to ARB do the commissions include a thorough discussion of the the statutory definition and limitations of "statewide greenhouse gas emissions." [CMUA(25)]

Agency Response: ARB is well aware that the CEC and CPUC recommendations were not binding on ARB and are not themselves regulations. The recommendations reflect the best judgment of these commissions on what ARB should consider in structuring electricity sector GHG reporting, as well as ARB's eventual GHG control measures. ARB considered the CEC and CPUC joint analysis and recommendations, and decided to incorporate many of the recommendations into the reporting regulation. Although AB 32 does not expressly require ARB to consider CEC and CPUC recommendations in developing a reporting regulation, it does not prohibit ARB from seeking guidance from these commissions with their expertise in the area of the electricity industry and regulation of the industry. AB 32 specifically names the CEC and CPUC as agencies ARB must consult with on energy-related matters during development of the scoping plan. It only makes sense that similar consultations would occur during development of the reporting program as well.

ARB disagrees that the commissions' recommendation to ARB or that ARB's regulation is erroneous. See response to comment A-10 for ARB's response to this aspect of the comment.

C-43. Assumptions Related to Default Emission Factors for Large Hydroelectric Facilities

Comment: The CPUC/CEC recommendations are based on the belief that nuclear and large hydro facilities are unlikely to change their operating parameters due to new contracts; therefore, new contracts associated with existing facilities of these types would not result in overall emissions reductions. DWR disagrees with these assumptions, as well as the ARB's recommended methodology. DWR is perpetually involved in energy efficiency projects, researching alternate types of water generators for the California Aqueduct or SWP facilities, and investigating the viability of additional features that increase the operational flexibility of the SWP while simultaneously reducing GHG emissions. Each year, as hydrologic conditions are confirmed, SWP may offer its excess generation and demand response capacity to other counterparties to fulfill their electric reliability obligations associated with California's resource adequacy and demand response requirements, and other capacity or energy related needs. The impact of ARB's proposed default emission factor may negatively affect the availability of clean hydroelectric power during critical peak hours. DWR strongly recommends that the default value for known sources of large hydroelectric energy be abandoned. [DWR(37)]

Agency Response: ARB agrees that new contracts associated with increased hydroelectric capacity and efficiencies should not be assigned a default emission factor at this time. ARB added language to section 95111(b)(3)(H) that requires reporting entities to distinguish contracts associated with increased efficiencies and increased capacity from those without such increases. In either case, no assignment of emissions or emission factors to hydroelectric sources is contained in the regulation. The CPUC/CEC recommendations include an annual review of default emission factors, and application of any emission factors to these sources will only occur following further public outreach and discussion and a formal rulemaking process.

C-44. Resources Procured to Meet Resource Adequacy Requirements
Comment: Recommend that the ARB should exclude resources procured to meet resource adequacy requirements from the default emission factor assignment for new contracts with existing resources. [AREM(46), AREM(T16)]

Agency Response: The commenter is referring to new contracts to procure capacity to insure energy resource adequacy where there is no actual purchase of power and, therefore, no electricity transactions. These types of contracts are outside of the scope of the proposed regulation and are not required to be reported.

C-45. Coordination of Reporting Requirements Between ARB and CEC
Comment: BPA currently makes annual reports of its mix of power resources to the California Energy Commission under the Power Source Disclosure Program. Since the information going to that program is closely related to greenhouse gas reporting, it would be efficient if reports from the electricity sector to the CARB and the CEC could be coordinated or consolidated. We encourage the Board and the Commission to work toward a single reporting process for both programs. [BPA(49)SW]

Agency Response: ARB will work with the CEC to reduce or avoid duplicative reporting in the future. Though we do not expect to eliminate all duplication in the near term, we will make every effort to coordinate data sharing between the CEC and ARB and to consolidate reporting procedures.

C-46. Use of Default Emission Factors
Comment: Concerned that, for transactions not covered by a supplier-specific ID, the proposed regulation could lead to overstatement of emissions of greenhouse gases attributable to PNW sales to California, through the combined

effect of identifying imports as unspecified and the adoption of a West-wide default emission factor of 1100 lb. CO_2 equivalent per MWh. These two assumptions should only be applied where they are truly necessary, and not to a known system like BPA's. BPA supports designing the regulation to achieve the greatest practicable accuracy in data on emissions. [BPA(49)]

Agency Response: The mandatory reporting regulation does not include assignment of a default emission factor for unspecified PNW sales, and ARB agrees that a default factor should be used only as a last resort. The proposed regulation includes voluntary reporting by asset owning/asset controlling suppliers and has been broadened to include suppliers with 50 percent or more of sales from renewable energy or with no more than 20 percent of sales from unspecified sources. ARB anticipates that major suppliers such as BPA will voluntarily report and be assigned supplier specific emission factors instead of a default emission factor.

C-47. Assigning Emissions to Unspecified Sources

Comment: The proposed regulation specifically identifies federal power agencies among potential suppliers of power from unspecified sources that are to be assigned a default emissions factor. BPA is concerned that power from a known fleet of resources, such as the CO_2-free FCRPS [Federal Columbia River Power System], should be recognized for the actual greenhouse gas emissions of those known resources and not be presumed to produce GHG at the default rate applied to unspecified resources that cannot be identified. BPA, as a federal power marketing administration, markets power from specific sets of generating facilities, and therefore is not a valid example of sellers from unspecified sources of power. [BPA(49)SW]

Agency Response: ARB agrees that the known resources operated by BPA should be assigned the correct emissions. In order to accurately characterize emissions associated with BPA's resource mix, ARB encourages BPA to apply for a supplier-specific emission factor.

C-48. Limitations on Assignment of Supplier-Specific ID

Comment: It is not clear why 10% or more of power purchases should disqualify a supplier from being assigned a supplier-specific ID, or result in application of a default emissions factors to a system's entire output. BPA annual reports to the CEC under the Power Source Disclosure Program show more than 10% purchases in some years. Historically, a 5-year rolling average of BPA's purchases would be under 10%, but future purchases may increase for such purposes as serving load growth. The supplier-specific emissions factor should be calculated using emissions data on all specified sources included in the supplier's sales and applying the default factor only to the remainder, regardless of the percentage of specified or unspecified purchases. [BPA(49)]

Agency Response: ARB agrees that BPA is the kind of supplier that should be represented by a specified power mix, but does not agree there should be no limitations on who can apply for their own emissions rate. If suppliers purchase a significant amount of power from unspecified sources, their emission factor would resemble the regional average. There is no incentive for suppliers whose emissions are greater than or equal to the regional average to seek a supplier specific factor. However, if they did, ARB would be unable to close the calculations on supplier emission factors because of the circularity that exists when suppliers buy from and sell to one another. Meeting one of the two following criteria is more appropriate: (1) the supplier is cleaner than average, or (2) the supplier is well defined and has few if any purchases from unspecified sources of power. As a result, the proposed regulation has been broadened to include suppliers with 50 percent or more of sales from renewable energy or with no more than 20 percent of sales from unspecified sources. The proposed changes also require suppliers who purchase more than 10 percent of the total electric energy they sell to report information on their specified and unspecified purchases so that emissions can be assigned to these transactions.

C-49. Use of E-tags

Comment: Since many E-tags identify specific generators or systems as sources for transactions, the regulation should allow entities to report greenhouse gas emissions from specific power resources identified in E-tags rather than report those transactions as unspecified. [BPA(49)]

Agency Response: It is our understanding that E-tags can sometimes identify the power source but not always. In particular, when a transaction goes through a power hub, the ability to determine the original source is lost. For that reason ARB adopted the definition for specified sources of power recommended by the CPUC and CEC, which does not rely on E-tags to identify sources. The definition calls for full or partial ownership in the source or identification of the source in a power contract. As BPA pointed out, E-tags may be used to identify the region of the transaction. In the future, the western region may have its own tracking system and ARB may need to revise the reporting regulation to accommodate additional methods to verify the source of a power transaction.

C-50. Assignment of 7.5 Percent for Transmission Losses

Comment: Attachment C, Interim Emission Attribution Methods for the Electricity Sector. This method sets transmission losses for imports at 7.5 percent. This value appears high. Where the loss factor is established by a posted OATT, this value should be used rather than a default 7.5%. [BPA(49)]

Agency Response: The Interim Emission Attribution Methods are not part of the proposed regulation. The ARB expects to set default emission factors, including a transmission loss factor, prior to assigning emissions, which would not occur before 2010. ARB will also revisit all the equations in the interim methods through both informal and formal rulemaking processes before those equations are employed in ARB's programs.

C-51. Substitute Power

Comment: The Sacramento Municipal Utility District (SMUD) requests that the California Air Resources Board modify the Proposed Regulation Order—Regulation for the Mandatory Reporting of Greenhouse Gas Emissions ('Reporting Regulations') to avoid additional reporting of the carbon content of substitute energy used for firming intermittent renewable resources and unit specific contracts. SMUD also submitted suggested language revisions to the regulation that would specify when to report substitute energy. [SMUD(50)]

Agency Response: ARB chose to revise the regulation to delete all reference to substitute power as a less complex way to address the issues raised by the commenter. In addition, ARB revised the definition of specified source to include California eligible renewable resources. The result is that reporting entities will not report power transactions firming renewable energy contracts unless the amount of firming power and the excess deviation in renewable energy do not net to zero at the end of the year. The regulation does not require the reporting entity to separately distinguish substitute power or firming energy from other kinds of power transactions. See response to comment C-15 for further discussion of this issue.

C-52. Emission Attribution Methods Should Be Regulatory

Comment: The emission attribution methods, while currently non-regulatory, are an integral part of the reporting requirements and should be integrated into the regulation as soon as possible. ARB (should) clarify their intentions regarding the interim emission attribution methods in Attachment C. The attribution method should be revised when the point of regulation is determined. [LADWP(BH6)]

Agency Response: ARB agrees that emission attribution methods may need to be regulatory in future emission reduction control regulations adopted by ARB, such as in a future emissions trading scheme; however, including these methods would be inappropriate at this time because many decisions have not yet been made on the basic design of these future regulations. When the design is determined, including point of regulation, the attribution methods will need to be revised with input from stakeholders and other members of the public.

C-53. Leakage and Contract Shuffling

Comment: Provisions that seek to address leakage and contract shuffling as part of the mandatory reporting regulation and attached emission attribution methods are in the wrong place, and should be separately addressed as part of the subsequent rulemaking required by AB 32 Part 4, section 38562. Agree with ARB that leakage and contract shuffling are important considerations that must be addressed directly. However, adjusting the emissions reporting to address contract shuffling introduces a myriad of challenges by shifting away from those very goals listed above (i.e., the requirements in AB 32) that are clearly identified in AB 32. [LADWP(BH6)]

Agency Response: The CPUC and CEC recommended that certain information be gathered and that emission assignments be made to discourage contract shuffling. ARB's regulation collects this information; however, how the information will be used and the future assignment of emissions will be discussed in the context of regulation development during a public process over the next two years. That process will also consider whether ARB should continue to collect the information or whether there will be new ways to address leakage and contract shuffling.

C-54. "Leakage" as Defined in AB 32 Does Not Occur With Contract Shuffling
Comment: AB 32 defines "leakage" as "a reduction in emissions of greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state." (Health & Safety Code section 38505(j)(emphasis added).) The AB 32 definition of leakage incorporates a geographical component that is based on where the GHG emissions are actually produced. The purest example of leakage is when a business shuts down an in-state facility in order to avoid California's GHG regulations and then replaces it with a similar facility outside the state. For retail providers, the concept of leakage is approached head-on by AB 32, which provides that "statewide greenhouse gas emissions" include the GHG emissions "from the generation of electricity delivered to and consumed in California, ...whether the electricity is generated in state or imported." (Health & Safety Code section 38505(m).) The AB 32 definition of statewide greenhouse gas emissions for the electric sector has a geographical component based on where the electricity is consumed, regardless of where the GHG emissions are produced. Therefore, a retail provider may not avoid AB 32 regulation merely by serving its load with imported power to supplant generation resources located in California. This is an important distinction that substantially reduces the opportunities for electric utilities to cause leakage as defined by AB 32. The statutory concept of "leakage" as defined in AB 32 is not implicated when a retail provider reduces the amount of out-of-state electricity it delivers to California that is consumed by its customers. (Health & Safety Code section 38505(j).). [CMUA(25)]

Agency Response: ARB agrees that AB 32's definition of "leakage" does not precisely dovetail with its definition of "statewide greenhouse gas emissions." But the question whether the practice of "contract shuffling" in the supply of electricity imports to California constitutes leakage as defined in AB 32 is not important to ARB's authority and duty to understand whether retail marketers are swapping high-emission imports for electricity from existing low-emission sources outside the state. As discussed in response to comment A-10, AB 32 requires ARB to design a program that will ensure that GHG emissions reductions – including those associated with imported electricity – are real, permanent, quantifiable, verifiable, and enforceable ...." (Health & Safety Code section

38562(d)(1).) Information about whether California retail providers are foregoing the importation of electricity from coal-fired plants they own outside California in favor of importation of lower-emission power from other sources is certainly relevant to the issue of whether reported reductions in statewide greenhouse gas emissions are real, for example, or exist only on paper. Even if "contract shuffling" to provide on-paper-only reductions in statewide greenhouse gas emissions is not "leakage" as defined under AB 32, as the commenter asserts, such "contract shuffling" is clearly counter to the policy concern expressed by the Legislature when it enacted the requirement that leakage be minimized, in addition to directly implicating ARB's mandate to ensure that reported reductions in GHG emissions be real.

C-55. No Evidence of a "Contract Shuffling" Problem; No Evidence of Electricity Sales That Comply With AB 32

Comment: The Energy Commission's and Public Utility Commission's joint recommendation to ARB included a determination that certain wholesale sales would not achieve real emission reductions; this determination was clearly erroneous and was not supported by any evidence adduced by the two commissions. The commissions collected no substantial evidence to demonstrate that any type of wholesale sale would be more or less likely to comply with AB 32. [CMUA(25)]

Agency Response: The CEC and CPUC issued their joint recommendation after lengthy review of issues and collection of public input. From ARB's perspective, their recommendations constitute expert opinion from two state agencies that have intimate knowledge of the electricity sector and its regulation. Expert opinion constitutes evidence on which ARB can rely for its own decision-making. Because the AB 32 program is the first of its kind in the western states and has no close corollaries, no actual data yet exists to show that "contract shuffling" will occur. But the scenarios discussed by the CEC and CPUC are straight-forward in explaining how some utilities might comply with AB 32 by substituting electricity from high-emissions plants they own outside California for low-emissions power from other existing sources. Given the efficiency of market systems, it is reasonable to expect companies to use the lowest-cost method that is available to them for complying with the program.

The commenter also states that the CEC and CPUC failed to collect substantial evidence as to the types of wholesale sales that are more or less likely to comply with AB 32. This comment is not clear, as nothing in the joint recommendation or in ARB's regulation identifies types of wholesale electricity sales that will be considered to violate AB 32. ARB assumes this comment alleges that CEC and CPUC have no substantial evidence to single out a certain type of wholesale sale – e.g., low-emissions imports that replace high-emissions imports from a generating plant owned by the retail provider – for an emissions attribution that the commenter considers punitive. See responses to comments C-21 and C-41 for ARB's views on the issue of so-called penalties for these transactions. For the reasons discussed in the preceding paragraph, ARB's decision to adopt this regulation is supported by substantial evidence.

C-56. Proposed Measure To Address "Contract Shuffling" Is Contradictory
Comment: The commenter rejects the logic of the CEC's and CPUC's concern over "contract shuffling," but even if the argument were accepted, the adjusted ownership share differential does not solve the purported problem. This is because the calculation only penalizes retail providers that maintain ownership in a high-GHG emitting facility. However, there would be no penalty if the retail provider were to sell its ownership share and use the proceeds to purchase power from an existing low-GHG emitting resource. This contradicts the very logic that formed the basis for the Joint Agencies' penalty recommendation. [CMUA(25)]

Agency Response: The mandatory reporting of ownership share differential and the formula to calculate it have been removed from the regulation, as described in responses to comments A-10 and C-60. ARB nonetheless disagrees that the original proposal's provisions requiring the reporting of the ownership share differential from high-GHG-emitting facilities owned by California retail providers contradicts the logic of the CEC and CPUC recommendation. California retail providers will be required to file reports under the regulation, and their ability to sell power from their out-of-state coal-fired plants to other buyers to reduce the emissions attributable to their electricity imports represents a significant opportunity for "contract shuffling." The fact that the regulation may not capture *all* situations that could involve "contract shuffling" – such as a California utilities' divestiture of ownership in an out-of-state coal-fired plant in combination with purchase of lower-emission electricity for its imports – does not mean ARB must refrain from collecting information that addresses a significant part of the issue.

C-57. Renewable Portfolio Standards in Other States Will Prevent "Contract Shuffling"
Comment: A central tenet in the Joint Agencies' theory of contract shuffling is that a non-California party in a region with no GHG cap will make a knowing exchange of its low-GHG resource and then replace it with a wholesale purchase of higher emitting resources from a California seller. The theory presupposes that the non-California party will have no regulatory requirements to purchase low-GHG resources, and therefore, may "shuffle" resources with impunity. Yet, this theory does not take into account that renewable portfolio standard (RPS) requirements will inhibit the benefits of "shuffling" and almost all of the states in the western interconnect have significantly stringent RPS requirements. CMUA believes that claims of widespread contract shuffling are both unrealistic and unsupportable since there is no record evidence in this rulemaking and little reason to think that California utilities will have the only claim on available low- and zero-GHG resources in the western interconnect. Therefore, CMUA argues that it's basically moot whether or not other states have GHG caps. The renewable resources will be in demand for their renewable attributes and California utilities will procure them on the market in the future just as they do

today. There is every reason to think that the environmental attributes for these low-GHG resources will remain bundled with the energy and it seems illogical that non-California entities would be willing to "shuffle" their contracts when those resources are needed to meet their own RPS requirements. [CMUA(25)]

The Final Market Advisory Committee ("MAC") Report shows minimal concerns regarding contract shuffling. The MAC Report states that the "introduction of a California cap-and-trade program could induce . . . [t]his shuffling of contracts" and that "some observers are concerned that contract shuffling could dramatically undermine a California cap-and-trade program" by noting that "there is sufficient generation capacity within the eleven states in the western power interconnect to entirely comply with expected emission reductions in California without any real change in generation." (Recommendations for Designing a Greenhouse Gas Cap-and-Trade System for California, Market Advisory Committee Report (June 30, 2007) at 44). The MAC Report, however, downplays this and states that "the opportunities for contract shuffling may be more limited than would initially appear" mainly due to the CPUC's procurement rule, the emission performance standard of SB 1368, and the fact that coal-fired plants which have the only significant incentive to shuffle comprise less than 1 percent of the imported power. (Id.) In light of this, the solution from the MAC Report "encourages" ARB "to develop an extensive plan for how to account for emissions associated with imported power." (Id.) [CMUA(25)]

Agency Response: In the previous two comments, the commenter discusses why the commenter believes that widespread contract shuffling will not occur. This discussion is not directly relevant to the proposed regulation. As noted elsewhere (see, e.g., responses to comments A-10 and C-21) this regulation as revised only requires and allows the reporting of certain information that could be relevant to a future determination by ARB that particularly transactions involve "contract shuffling." ARB will have further opportunity to evaluate the potential risk of contract shuffling prior to adopting any substantive AB 32 emission controls affecting the electricity sector.

C-58. Assigning Default Factor to Zero Emission Resources

Comment: The proposed mandatory reporting regulation and attached emission attribution methods do not treat generation from zero emission resources consistently. The assignment of default emission factors to large hydro resources should not be pursued. The definition of renewables may change in the future and therefore a default for those resources may be inappropriate. LADWP recommends that emissions should reflect the generation source whenever the source is known. Default emissions should not be assigned to specified zero emission generating resources. [LADWP(BH6)]

Agency Response: ARB acknowledges the need for further public discussion on how to address contract shuffling and whether to use default emission factors to discourage it. Although the regulation does not assign default emissions to large hydroelectric resources, ARB is collecting information relevant to this issue because it may be necessary to determine whether future control measures are resulting in actual emissions reductions. ARB anticipates that major suppliers will voluntarily report and be assigned supplier specific emission factors. As a result, ARB anticipates that most purchases from hydro facilities will be assigned a supplier emission factor and not a default emission rate. For a description of changes made to the regulation that relate to this issue see responses to comments C-28, C-43, and C-46 for further discussion.

C-59. Delete Ownership Share Reporting Requirements

Comment: Recommend that emissions should be reported based on actual MWh received from all generation resources, including owned facilities, jointly owned facilities, and purchased power. Reporting based on ownership share should be deleted from the reporting requirements. [LADWP(BH6)]

Agency Response: The regulation does include the reporting of actual MWh received from all sources as well as collecting ownership share information. The regulation does not stipulate how ownership share information will be used or how emissions will be assigned to retail providers. That will be decided during the development of future regulations. However, on the recommendation of the CPUC and CEC, ARB decided that ownership share information should be collected for possible future use in addressing out-of-state contract shuffling. If it is determined that this information is not needed in the future, ARB will amend the regulation to delete the requirement.

C-60. Delete Ownership Share Provisions from the Regulation

Comment: The ownership share differential provision should be deleted from section 95111(b)(3)(N), the paragraph at section 95111(b)(3)(P) containing the adjusted ownership share differential provision should be deleted in its entirety, and section 95111(b)(3)(R) should be deleted in its entirely. The ownership share differential and adjusted ownership share differential provisions do not meet the necessity standard because they are flawed and not supported by AB 32, and there is no substantial evidence that they are reasonably necessary. ARB does not have authority to regulate out-of-state transactions of electricity that is not imported into California. The commenter does not oppose ARB requiring retail providers to report the following information for power plants they own in full or in part: facility name, facility ID, generating unit ID, and percent ownership share at the facility and unit levels, as applicable. It is reasonable for ARB to collect information to determine a plant ownership share. The concept of ownership share differential based on the difference between an owner's contractual allocation and the electricity actually taken is unnecessary. Since AB 32 only applies to statewide greenhouse gas emissions as that term is defined in section 38505(m), a load-based reporting mechanism only requires information on the electricity actually received to serve load in California. Once section 95111(b)(3)(N) is amended to include ownership information from all owned plants located out of state, section 95111(b)(3)(R) is duplicative and should be deleted in its entirety. [CMUA(25)]

Agency Response: In response to this and other comments, ARB removed from the regulation the requirement that California retail providers calculate and report ownership share differential and adjusted ownership share differential for all generating plants it owns. In place of those requirements, the modified regulation provides retail providers the opportunity to voluntarily report wholesale sales and reductions in power generation at power plants they own. Section 95111(b)(3)(Q) still requires retail providers to report the following information for power plants that they own in full or in part: facility name, ARB-designated facility ID, generating unit ID, percent ownership share at the facility level and generating unit level, and net power generated in the report year. Sections 95111(a) and 95111(b)(3)(A) require fuller reporting of emissions and other information for all power plants that are operated by California retail providers.

ARB does not agree that the original provisions exceeded its authority under AB 32 or that they did not meet the necessity standard in the Administrative Procedure Act. For an explanation of how this provision is consistent with and supported by AB 32, see response to comment A-10. See response to comment A-20 for a discussion of why these provisions meet the necessity standard and other requirements of the Administrative Procedure Act.

C-61. Emissions Responsibility for Full Ownership Share

Comment: The proposed regulation would require that utilities not only account for GHG emissions for in-state energy consumption but also for energy consumed outside the state, because the attribution methodology would assign GHG emissions to a utility for its full ownership share of energy even if the utility received up to 10 percent less than its full ownership share. This is inconsistent with the express statutory language of AB 32. Government Code Section 11342.2 requires regulatory language be “consistent and not in conflict with the statute and reasonably necessary to effectuate the purpose of the stature.” [LADWP(BH6)]

Agency Response: ARB does not agree there is an inconsistency between the regulation and AB 32. First, the commenter refers to an attribution methodology that is not part of the reporting regulation. In addition, although reporting of ownership share is required, the reporting of certain information on out-of-state sales has been revised to be voluntary rather than mandatory.

And last, ARB has regulatory authority to gather information that may be needed to design future regulations and, in anticipation of those regulations, collect information that may be needed to assure emission reductions are real. The mandatory reporting regulation does not commit to a particular approach for determining emission responsibility for retail providers. That will be determined in future regulatory processes, during which we anticipate the reporting regulation will be revised to reflect the needs of the chosen regulatory approach. See response to comment A-10 for further information why ARB has authority to collect this information.

C-62. Delete Native Load and Revise Attribution Equations
Comment: The oversimplified method in section 95111(b)(3)(H) of the regulation would overestimate the emissions for power used to serve native load by incorrectly attributing 100% of the generation from baseload generating facilities to native load, when in reality a portion of the generation from baseload facilities is used for wholesale sales. In addition, section 95111(b)(3)(H) would restrict the hydroelectric generation that could be designated as serving native load to only "output the reporting entity takes whenever it is available," which would eliminate hydroelectric generation from controlled resources such as Hoover Dam and pump storage facilities. Recommend that section 95111(b)(3)(H) be deleted and replace the term "Native Load" in an emissions attribution equation with renewable generation and zero emission generation to serve native load. [LADWP(BH6)]

Agency Response: ARB revised section 95111(b)(3)(H)2., now numbered 95111(b)(3)(I)2., to remove the stipulations on hydroelectric facilities. With this change this operator will be able to claim the power purchased from Hoover Dam as native load. Regarding the assignment of 100 percent of generation from base load generating facilities to native load, section 95111(b)(3)(H)3. (now section 95111(b)(3)(I)3.) has been revised to allow the retail provider to select a capacity factor of their choice. The operator can select a higher factor and avoid designating too much generation to native load. The operator can also choose not to use the option available in section 95111(b)(3)(I)3., but to select facilities based on the other criteria in sections 95111(b)(3)(I). Emission calculations for native load and the relevance of native load will need to be re-examined after the point of regulation is determined.

C-63. Retail Sales Emission Factor
Comment: Recommend revising the equation for retail sales emission factors in the emissions attribution methods. The equation should subtract out losses incurred while providing wholesale transmission service for power belonging to other parties that is wheeled through the retail provider's system. [LADWP(BH6)]

Agency Response: The emissions attribution methods are not regulatory and will be revised when the point of regulation is determined. At that time, ARB will revisit all the equations in the methodologies that remain relevant, including the retail sales emission factor. In the meantime, ARB will keep this comment on file and appreciates the commenter's careful examination of the equations.

C-64. References to NERC E-Tags
Comment: Recommend that NERC e-tags not be used for emissions reporting or verification purposes. The tag can show a source that differs from the source

agreed to in the transaction. Recommend that settlement data be used to report and verify electricity transactions. [LADWP(BH6)]

Agency Response: ARB added language to section 95111(b)(2)(C) and (G) to include the use of settlement data and other information as recommended by this commenter. Also, e-tags are referenced to confirm region of origin, not the source.

C-65. Revise Provision For Retention of Documentation of Reduced Power Demand
Comment: The commenter recommends revising section 95111(b)(3)(Q) to eliminate references to the adjusted ownership share differential; as revised, the provision would state that retail providers "may retain for purposes of verification" documentation showing that operations at the power plant were reduced because of reduced demand for electricity. The retained language is acceptable because it concerns the verification of power that was delivered and consumed in California, and is not used to penalize the retail provider for power that was delivered and consumed outside California. [CMUA(25)]

Agency Response: ARB deleted original section 95111(b)(3)(Q) in its entirety as part of its deletion of the adjusted ownership share differential provisions and formula from the regulation. However, the revised provisions relating to coal-fired power plants owned by California retail providers gives retail providers the option of reporting to ARB the amount of power generation that was reduced because of reduced demand for power (section 95111(b)(3)(R)(2)). Any operator covered by the reporting regulation must retain records to verify the contents of its GHG emissions report (see sections 95104 and 95105). Therefore the effect of retained section 95111(b)(3)(R)(2) and the language that the commenter urged ARB to retain from 95111(b)(3)(Q) are the same, and no revision is necessary.

C-66. Consistency with 2020 GHG Emissions Limit
Comment: The goal and purpose of AB 32 is to produce emission reductions to achieve the 2020 limit. Statewide greenhouse gas emissions are the distinct and measurable emissions that were counted to calculate the limit. An inconsistency would result if ARB were to attribute emission obligations for non-statewide greenhouse gas emissions to measure achievement of the 2020 limit. [CMUA(25)]

Agency Response: This comment relates to ARB's collection of information about certain out-of-state electricity transactions to assess whether California utilities are substituting electricity imported from "clean" existing sources for electricity they would formerly have imported from high-emission plants they own in other states. This information is being collected to determine in future years whether reported reductions in GHG emissions are real and the degree to which reductions in "statewide greenhouse gas emissions" are offset by corresponding increases in other GHG emissions. See response to comment A-10 for further discussion of this point. ARB has not decided what regulatory use it will make of the information it receives relating to possible shifts in the types of electricity that California retail providers import into the state, so it is premature to argue that ARB's use of emission attributions creates an inconsistency with another part of the AB 32 program.

§95112. Data Requirements and Calculation Methods for Cogeneration Facilities

C-67. Cogeneration Biomass Facility Reporting Requirements

Comment: The operator runs 5 cogeneration facilities that combust solid biomass. Several co-fire with fossil fuels for start-up, shutdown or malfunction operating periods only. Requests clarification as to whether they would report under proposed section 95111 because they combust biomass rather than section 95112 because they are a cogeneration facility. Section 95112 seems to be focused on the combustion of fossil fuel. [SPI(5)]

Agency Response: The cogeneration operator would report under section 95112. This section includes requirements that cross-reference section 95111. Section 95112 requires cogeneration facilities to report CO_2, N_2O, and CH_4 emissions from stationary combustion using the calculation methods specified in section 95111. Methods to calculate emissions from biomass combustion are provided. Distribution of emissions required in section 95112 applies to CO_2 emissions from fossil fuel combustion, including start-up, shutdown or malfunction operating periods.

C-68. Clarify or Delete NAICS Code Request for Off-Site Power Purchases by Utilities from Cogen Facilities

Comment: The reporting regulation should either allow identification (via the NAICS Code) of a utility as an off-site power purchaser or delete the requirement in section 95112(a)(3)(B). [APC(8)]

Agency Response: ARB revised the regulation to clarify that end-user's NAICS codes are only required when electricity is "sold or provided *directly* to end-users." A cogeneration facility operator only reports wholesale electricity sales exported directly out-of-state, if applicable, and total wholesale electricity sales. When electricity is sold wholesale within California, neither the name of the purchasing utility nor a NAICS code is required. Instead, electricity transaction information is provided by retail providers under section 95111. For consistency, ARB updated the thermal energy production section of the greenhouse gas emissions data report to require that the "amount of thermal energy sold or provided to the cogeneration thermal host" be reported. Because in some cases the thermal host may be located on-site, ARB deleted the reference to "off-site end-users."

C-69. Clarify Thermal Host Operations are Excluded from Reporting Requirements for Cogeneration Facilities

Comment: Cogeneration facilities are unique in that they have cogeneration operations as well as thermal host operations. The goal of AB32 is to collect data for the cogeneration operations only. To clarify, the commenter recommends the following change in language in the first sentence of 95112(a): "The operation of a cogeneration facility, *excluding thermal host operations*...." [APC(8)]

Agency Response: ARB finds that no change is needed. The definition of a cogeneration facility, which may include one or more cogeneration systems, is specific to "sequential generation of multiple forms of useful energy… for an end-use other than electricity generation." The definition does not include operations of the thermal host, defined as "the user of the steam or heat output of a cogeneration facility."

C-70. Clarify Best Available Data and Methods Approach for Cogeneration

Comment: Some cogeneration plants have multiple steam lines, not all of which are measured with totalizers to obtain annual steam generation. As such, these cogeneration facilities may not be able to provide measureable data on all steam lines, particularly small lines. To be consistent with the "Best Available Data and Methods" approach for this regulation, please change the wording to read: "Estimated amount of thermal energy..." This would allow facilities to estimate the annual thermal output without having to install totalizers on every steam line, particularly minor steam lines. [APC(8)]

Agency Response: The regulation does not specify that totalizers be installed on all steam lines, or preclude engineering methods or other means of calculating thermal energy for minor steam lines. Use of totalizers or other direct measurement of thermal energy is recommended for steam outputs that would significantly affect the distribution of emissions between electricity production and thermal energy production.

C-71. Clarify Estimation of Efficiency of Electricity Cogeneration

Comment: The draft regulation requires that cogeneration facilities report electricity generation efficiency. This is not a measured parameter. Rather it will be estimated or assumed as part of the effort to generate the greenhouse gas inventory. To clarify that this is not a required measurement, please change the wording from "Efficiency" to "Estimated efficiency." [APC(8)]

Agency Response: ARB does not agree with this recommendation. To ensure consistency and rigor in reporting, operators are required to calculate the electricity generation efficiency based on the equation in the regulation at section 95111(b)(4)(A)1. If parameters needed in the equation are unknown, the operator must use the default values provided. Also please see responses to comments C-74 and H-29.

C-72. Delete Requirement for Reporting Heat Recovery Steam Generator (HRSG) Data by Cogeneration Facility Operators

Comment: The mandatory reporting regulation draft requires the reporting of the useful thermal output, amount of thermal energy sold off-site and the amount of thermal energy consumed on-site. This data is then used to calculate the distributed emissions from a cogeneration facility. This is consistent with the Power and Utility Reporting Protocol (PUP) issued by the California Climate Action Registry. To reduce the reporting burden, delete the requirement of reporting HRSG data since it is inconsistent with the PUP and the additional data will not be used in the calculation for distributed emissions. [Calpine(24)]

Agency Response: ARB supports no change related to this comment. The HRSG efficiency, if known, may be used in the distributed emissions equations for topping cycle and bottoming cycle plants. See sections 95111(b)(4)(A) and (B). HRSG output and fuel fired for supplemental firing are required inputs for the bottoming cycle plant distributed emissions equations. See section 95111(b)(4)(B).

C-73. Provide Credit for Biogas Use and Distributed Generation Benefits in Reporting Requirements for Cogeneration Facilities

Comment: The following changes are requested: Credit biogas utilization with a CO_2 sink factor, recognizing the benefits of using this fuel, and, credit facilities who have invested in onsite generation, due to the reduction of line losses and the associated emissions [FCE(39)]

Agency Response: ARB supports more reliance on biomass-derived fuels as substitutions for fossil fuels when net greenhouse gas reductions can be achieved. The mandatory reporting regulation requires facilities to report CO_2 emissions from biomass-derived fuel combustion separately from combustion of fossil fuels. The proposed regulation also provides additional methods and reduced requirements for biomass facilities. Any credit that may be allocated to a cogeneration facility would be determined in the future during the development of direct greenhouse gas compliance requirements or an emissions trading system. The potential for credit is one reason why emissions reporting for biomass-derived fuels is required.

C-74. Efficiency Factors to Distribute Emissions for Topping Cycle Plants

Comment: The emissions distribution for topping cycle units uses what is commonly referred to as an efficiency method. This method allocates emissions between useful energy outputs based on their relative efficiencies. The particular calculation methodology allows an entity to choose among several options for determining its efficiencies. This flexibility allows a facility to determine the most accurate efficiency for that particular facility. Commenter supports the proposed methodology for topping cycle units. [EPUC/CAC(42)]

Agency Response: To ensure reporting consistency, the regulation was revised to expressly require that operators use and report the efficiencies, if known; otherwise, the provided default values must be used. See also responses to comments C-71 and H-29. This modification was not in response to the comment, but relates to the issue addressed there.

C-75. Distribute Bottoming Cycle Plant Emissions to Manufacturing Process

Comment: The proposed allocation methodology for bottoming cycle plants would allocate emissions between the industrial process and any useful energy outputs. Making any allocation does not make sense because all of the emissions are attributable to the industrial process and should be allocated to it. The electricity is generated from waste heat which would otherwise be exhausted into the atmosphere and should be considered carbon-neutral. A rational treatment would be to recognize that bottoming-cycle cogeneration, without supplemental firing, does not consume any fuel to generate electricity. All fuel is required for the industrial process, such as calcining, and would be consumed whether the generation was taking place or not. The draft regulation should be revised to allocate all of the emissions to the industrial process which requires all of the fuel input and should be assigned responsibility for the carbon emissions. [EPUC/CAC(42)] Data and calculation methods are not applicable to many manufacturing operations where the fuels are consumed in the manufacturing process equipment and the process emissions pass through the waste heat recovery system. [PPG(17)]

Agency Response: ARB considered the option to distribute all emissions for bottoming cycle plants to the manufacturing process, which would effectively mean that the electricity generated would be "carbon-neutral." ARB was concerned this could encourage less efficient manufacturing processes or the burning of excess supplemental fuel in order to generate more waste heat to produce additional "carbon-neutral" electricity. In such cases the recommended change to the regulation may result in greater CO_2 emissions. For that reason ARB rejects the proposed change. Bottoming-cycle cogeneration facilities wishing to claim carbon-neutral electricity generation could explore development and approval of a project protocol with criteria to demonstrate GHG reductions.

The final regulation includes a requirement for bottoming cycle plants to distribute emissions to electricity, thermal energy, and manufacturing processes. ARB believes the methodology provides a conservative but reasonable approach to emissions distribution. The method could be revisited and changed as future emissions control regulations are developed in subsequent public processes.

§95113. Data Requirements and Calculation Methods for Petroleum Refineries

C-76. Use Different Emission Factor for Asphalt Blowing

Comment: Staff Report page A-58 and A-59. The default emission factor from the Inventory of U.S. GHG Emissions and Sinks for asphalt blowing is 2,555scf $CH_4/10^3$bbl) not 10^6bbl. [USEPA(19)]

Agency Response: This error has been corrected.

C-77. Check Equipment Fugitive Emission Equation for Dimensional Consistency
Comment: Dimensional units for one of the equations for the calculation of equipment fugitive VOC emissions appears incorrect. Staff Report page A-61, section 95113(c)(4)(A)(2), Equipment Fugitive Emissions - Performing dimensional analysis on $E_{VOC-L} = \sum C_{ief} \times SV^{\beta}$ does not seem to produce kg/hr, unless the units of measure for C_{ief} are (kg/hr)/ppmv. [USEPA(19)]

Agency Response: The equation has been modified to address this concern.

C-78. Specification of Method for Measuring Carbon Content for Flare Pilot/Purge Gas
Comment: Suggest specifying the ASTM method used to sample and measure carbon content of natural gas used as flare pilot and purge gas. Staff Report page A-63, section 95113(d)(1), Flaring. Consider specifying what method, e.g., ASTM, will be used to sample and measure carbon content of natural gas combusted as flare pilot and purge gas. [USEPA(19)]

Agency Response: The suggested change has been made.

C-79. For Flaring Emissions Use Consistent Methods if Feasible
Comment: Staff Report page A-63-64. For flaring emissions, if feasible reporters should be required to use consistent methods. Due to the fact that the reporting regulations for reporting flaring GHG emissions are based on AQMD/APCD reporting regulations, there will be significant differences in the level of uncertainty associated with flaring emission data. [USEPA(19)]

Agency Response: We acknowledge these uncertainty differences in flaring emissions, due to the differences in flare reporting regulations among the three California air districts that have them. Flaring emissions are a relatively minor GHG source, however. Flaring is more strictly regulated at California's larger refineries, located in the Bay Area and South Coast AQMDs. The three reporting refineries in the San Joaquin Valley Air Pollution Control District (SJVAPCD) will be required to use default emission factors, which tend to be conservative and thus overestimate GHGs from flaring. Due to the small magnitude of this source, ARB did not believe it was necessary to require these Valley refiners to install new flare sampling and monitoring devices.

C-80. Flare Emission Equations – Section 95113(d)(2)(A)
Comment: Suggest revision to the equation for calculation of emissions from flares. The revised equation for CO_2 accounts for the possibility that CO_2 is present in the flared gas stream and would be emitted with the flare exhaust. The

equation for CH_4 assumes 0.5% residual, unburned CH_4 remaining in the flared gas based on industry practice for well designed and operated flares, such as in refineries. Request that calculation methods for natural gas used as flare pilot and purge gas be made consistent with requirements under 95115(a)(2)(B) and (C). [API(12)]

Agency Response: Given the fact that flaring emissions represent a very small fraction of total refinery GHG emissions, ARB believes that using a reporting methodology based on existing AQMD/APCD flaring reporting requirements will provide adequate emissions data, so the proposed changes to the equations were not necessary. Furthermore the current approach in the regulation does not impose any additional measurement or instrumentation requirements on reporters. Staff did modify the text of this section (95113(d)(1) to make reporting requirements for natural gas pilot and purge gas consistent with other natural gas emission requirements as requested by the commenter.

C-81. Implementation of LDAR Programs at Refineries – Section 95113(c)(4).
Comment: Emissions estimates based on component counts and average emission factors indicate that methane fugitive emissions represent 0.1 to 0.2% of the total GHG inventory for small and large refineries respectively. Recommend an approach developed by API which initially uses average emission factors to estimate fugitive emissions. Subsequently, if these estimated emissions exceed de minimis levels, refineries would adopt a more refined approach, such as using a Leak/No Leak or a correlation equation approach. Commenter also points out that the fugitive emissions methods in the regulation may not be consistent with measurement approaches used at some facilities. These discrepancies are due to differences in air district requirements for refinery LDAR program implementation. [API(12)]

Agency Response: A USEPA workshop in 2006 focusing on refinery fugitive emissions concluded that emissions from refinery and natural gas operations may be 10 to 20 times greater than the amount estimated using standard emission factors. The EPA workshop presentation is included as part of the public record references for the Staff Report. This conclusion was based on studies performed in Europe over the last decade, and more recently in Canada using relatively new measurement technology.

Because of the potential unreliability and uncertainty of average or default emission factors and the resulting degradation in the emissions estimation accuracy, we did not make this suggested change. California air districts currently require refiners to establish leak detection and repair (LDAR) programs based on EPA Method 21 – Determination of Volatile Organic Compound Leaks. Recognizing that the use of standard emission factors has the potential to significantly underestimate refinery fugitive emissions, and that all California petroleum refineries currently have LDAR programs in place, ARB believes the best option is to require the extension of existing LDAR measurement procedures to all natural gas and refinery fuel gas components.

Based on input from API and refinery staff, the fugitive reporting regulations were modified and adapted to reflect the measurement approach used at the specific facility as required by the local air district. These changes were made to reflect differences in air district LDAR program implementation requirements with regard to the use of a dilution probe with the Method 21 VOC analyzer.

C-82. Use of EPA TANKS Program to Estimate Methane – Section 951139(c)(3).
Comment: The EPA TANKS model is not capable of directly calculating CH_4 emissions from crude oil storage tanks. The API Compendium presents a conservative approach which estimates THC or VOC emissions using this model. Recommend that the EPA TANKS approach to calculating methane emissions from storage tanks be optional, with the decision based on an evaluation as to whether facility layout or operating practice would be conducive to the presence of CH_4 in the crude oil stored at the facility. Commenter further states that estimating methane emissions from other refinery fractions after distillation would be a waste of resources and produce meaningless results. [API(12)]

Agency Response: While actual measurement of methane emissions are certainly preferable to model based emission calculations, ARB has specified the use of the EPA TANKS model to estimate methane emissions from crude oil and asphalt product storage tanks. As the commenter points out, the EPA TANKS model is capable of calculating VOC emissions when Raoult's Law constants are used. The model also provides estimates of VOC emissions from crude oil storage. ARB is effectively taking the approach advocated by the commenter, which is to use the EPA TANKS model to estimate VOC emissions. Making the use of the model optional is not feasible because it would lead to inconsistent emissions reporting for refineries and undermine confidence in the reported emissions.

C-83. Proposed Small Refiner Alternative Monitoring.
Comment: The proposed refinery fuel gas sampling requirements (daily carbon content and HHV) represent a significant financial hardship for small refiners. Recommend amending sampling procedures to require twice monthly sampling. [SJRC(20)]

Agency Response: The regulation has been modified to at section 95102(a)(177) to include a definition of a "small refiner" as already defined by the California Code of Regulations. Sampling frequency for refinery fuel gas systems at California refineries designated as "small" has been changed from daily to weekly sampling of refinery fuel gas carbon content. See section 95125(e)(3)(A). This change effectively reduces the number of annual samples required from 365 to 52 (per refinery fuel gas system) and should significantly reduce the associated financial burden.

C-84. Provide Small Refineries Less Rigorous Sampling Scheme

Comment: Request that the "small refineries" (as defined in the California Code of Regulations) in California be allowed to follow a less rigorous refinery fuel gas sampling scheme to minimize cost. Request that small refineries be allowed to sample refinery fuel gas HHV and carbon content twice per month. Current daily sampling requirements would cost over $200,000 annually per facility. [KERN1(26)]

Agency Response: As noted in the response to C-83, the regulation has been modified to allow California refineries meeting the definition of a small refiner (as defined in the California Code of Regulations) to sample refinery fuel gas HHV and carbon content on a weekly basis. This reduced sampling regime will reduce sample volume by a factor of seven and should also reduce associated costs by roughly the same amount (to less than $30,000 annually). The two "small" California refineries represent approximately 2.5% of the total refinery capacity in the State. Thus a relaxation of the sampling frequency should not cause a significant reduction in our ability to accurately determine petroleum refining GHG emissions in the State. The fact that each of these refineries has a single refinery fuel gas collection and blending system also suggests that their refinery fuel gas composition is probably much less variable than in larger facilities where there are multiple systems.

C-85. Carbon Content Measurement Frequency

Comment: Require a monthly carbon content measurement frequency for associated gas/produced gas and low Btu/VRU gas. [WSPA(23)] Daily analysis of associated gas would be very costly. [MKP(45)]

Agency Response: Section 95125(c)(1)(A)2. of the regulation has been modified such that emissions resulting from the combustion of associated gas are treated in a manner identical to natural gas. That is, if the HHV value of associated gas is between 975 and 1100 Btu/scf (inclusive), HHV must be determined monthly, and combustion emissions calculated using a default emission factor provided by ARB. If the associated gas falls outside this range, carbon content is determined on a monthly basis and used to calculate CO_2 combustion emissions.

CO_2 emissions resulting from the combustion of low Btu gas and gas from Vapor Recovery Units (VRU) are calculated consistent with procedures developed for reporting to air districts, as specified in section 95113(d). For emissions not reported in an air district program, section 95113(e)(3) provides methods applicable where low Btu or VRU gases are destroyed by incineration or combustion as a supplemental fuel. In this case, carbon content of these gases must be determined on a quarterly basis. Emissions from the combustion of low Btu and VRU gases appear to be minor sources, and these changes (described in the previous paragraph) should provide some relief in the case of oil and gas production fields where sampling locations can be widely distributed geographically, making sampling logistically difficult, expensive and time consuming.

C-86. Flow Rate and Carbon Content Methodology
Comment: Provide additional flexibility in the determination of refinery fuel gas combustion emissions. Provide the option of using a continuous GC analyzer to determine refinery fuel gas carbon content. [WSPA(23)]

Agency Response: Section 95125(d)(3)(A) has been modified to provide this option. This change will not result in a degradation of emissions data as the determination of carbon content will provide rigorous emissions data.

C-87. Use of CEMS for Combustion and Process Emissions
Comment: For refineries and hydrogen plants, provide the option of using CEMS for the determination of both combustion and process emissions. [WSPA(23)]

Agency Response: Sections 95113(a) and (b) provides the option to install and use CEMS for the determination of combustion and process emissions, respectively. In the case of hydrogen production, Section 95114(b)(1), allows CEMS use for both process and combustion emissions.

C-88. Reporting Hydrogen Plant Emissions with Refinery Emissions
Comment: For refineries, provide the option of reporting hydrogen plant combustion and fugitive emissions along with their other refinery combustion and fugitive emissions. [WSPA(23)]

Agency Response: Greenhouse gas emissions resulting from the production of hydrogen represent a significant portion of typical refinery GHG emissions. In addition, at some California refineries hydrogen production is accomplished by parties that operate independently of the refinery. To insure consistent reporting for this important GHG source, it is necessary to require separate reporting of GHG emissions from hydrogen production whether production is done by the refiner or by a third party. For that reason ARB rejects the suggested modification.

§95114. Data Requirements and Calculation Methods for Hydrogen Plants

C-89. Include CO_2 Reporting for Hydrogen Plants, Do Not Subtract Emissions
Comment: Staff Report page 48. Support ARB approach for the accounting of CO_2 from hydrogen plants and not subtracting the CO_2 from the facilities' emissions reports. [USEPA(19)]

Agency Response: GHG reporting requirements for "transferred CO_2" remain unchanged and include the suggested approach.

C-90. Reporting Requirements for Hydrogen Plants (carbon exports) (95114)
Comment: Request that provisions be made to report carbon monoxide and dioxide which is shipped or piped to off-site customers. Request the ability to subtract these fractions from facility GHG emission reports. [Praxair(22)]

Agency Response: Provisions have been added at section 95114(a)(6) to allow hydrogen plants to report their transferred CO_2 and CO emissions. However, the regulation does not permit transferred CO_2 and CO to be subtracted from facility emissions totals. The reporting regulations are designed to provide information to enable emissions accounting. Decisions regarding the responsibility for GHG streams such as "transferred CO_2 and CO" shall be made as the implementation of AB 32 progresses.

C-91. Reporting Hydrogen Used as a Transportation Fuel, Section 95114(a)(2)
Comment: Request guidance as to how to report the volume of hydrogen sold as transportation fuel when that hydrogen is drawn from a supply pipeline and not from a single, specific hydrogen production facility. [APC(41)]

Agency Response: The operative term here is "sold". When a commodity such as hydrogen is sold, billing information provides volume information. ARB believes it should be possible to ascertain with reasonable certainty the disposition of hydrogen sold to a particular customer since this should not be confidential information.

C-92. Feedstock Carbon Content Sampling Frequency Excessive, 95114(b)(3)
Comment: The proposed sampling frequency for hydrogen plant feedstock (the daily determination of carbon content) is excessive; weekly sampling is suggested as an alternative. [Praxair(22)]

Agency Response: In the case where pipeline quality natural gas is the only hydrogen plant feedstock, the regulation specifies monthly determination of carbon content. In situations where non-standard species such as naphtha and refinery fuel gas are used as feedstocks, daily determination of carbon content is required. Hydrogen plant process emissions of CO_2 derived from feedstock materials represent a significant contribution to a refinery or hydrogen plant GHG emissions inventory, perhaps 20% of more of total emissions. The magnitude and importance of these emissions are projected to increase in the future as demand for hydrogen in the refining process increases. The regulation does provide flexibility as to the methods which refiners and hydrogen plant operators may use to measure and quantify both combustion and process emissions. Due to the magnitude and importance of process and combustion emissions generated during hydrogen production, weekly determination of feedstock carbon content would not adequately characterize these emissions when diverse and variable feedstocks are used to produce hydrogen. For that reason, ARB rejects the suggested change.

C-93. Fuel Gas Carbon Content Sampling Frequency Excessive, 95125(e)(3)(A)
Comment: The requirement to sample refinery fuel gas carbon content daily as excessive; weekly sampling would be sufficient. [Praxair(22)]

Agency Response: Refinery operators are required to sample carbon content and HHV of each refinery fuel gas (RFG) system and calculate a RFG system specific CO_2 emission factor on a daily basis. This sampling scheme was adopted due to variable content of RFG and the importance of RFG as a fuel in refineries. Forty percent or more of CO_2 emissions at a typical refinery may result from the combustion of RFG and its use as hydrogen plant feedstock. ARB does not agree that weekly sampling is sufficient given the variable content and its significance to overall emissions. An independent hydrogen producer may receive RFG from a refinery where they are contracted to supply hydrogen. It is the responsibility of either the hydrogen plant operator or the refiner to determine the carbon content of the RFG feed to the hydrogen plant.

C-94. Natural Gas Sampling Should be Monthly, 951149(b)(3)
Comment: For hydrogen plants, suggest that the sampling frequency for natural gas used as a fuel or feedstock should be monthly. [Praxair(22)]

Agency Response: The sampling frequency for pipe-line quality natural gas (HHV between 975 and 1,100 Btu/scf, inclusive) has been changed to monthly.

C-95. Typo in Section 95114(b)(1)
Comment: Hydrogen Plant (CEM). There is a typographic error in section 95114(b)(1). The reference to section 95125(g)(6) should read 95125(g). [WSPA(23)]

Agency Response: This error has been corrected.

C-96. Reporting Fugitive Emissions, Section 95114(a)(4)
Comment: Question the cost benefit for estimating methane fugitive emissions for refineries and hydrogen plants. [APC(41)]

Agency Response: The magnitude and relative contribution of fugitive emissions from petroleum refineries and hydrogen plants remains an area of some uncertainty. The fugitive emissions measurements methods specified in this regulation are based on US EPA Methods and California air district rules and regulations. Although operators may choose to calculate and report fugitive emissions using *de minimis* methods as permitted in the regulation, ARB does not feel that fugitive emissions can be ignored.

C-97. Reporting Methods for Combustion and Process Emissions, Section 95114(b)
Comment: Support the regulatory language presently in place that provides three alternative methods for estimating process and combustion emissions. [APC(41)]

Agency Response: These options remain unchanged; all should result in very accurate emissions for reporting.

C-98. Reporting Mixed Fuels and Feedstocks, Section 95114(b)(2) and (3)
Comment: Provide clarification of reporting requirements in the case of fuel and feedstock mixtures. [APC(41)]

Agency Response: The language in these sections was modified to provide guidance for flow and composition determination in the case of fuel and feedstock mixtures. ARB believes this approach is preferable to trying to cover every conceivable configuration and process whereby fuels and feedstock are mixed.

§95115. Data Requirements and Calculation Methods for General Stationary Combustion Facilities

C-99. GSC - Reporting Other Emissions
Comment: Do not require General Stationary Combustion sources to report process, fugitive, and vehicle fleet emissions. These emissions could be difficult to estimate and in many cased will be minimal. [CLFP(10)]

Agency Response: At this time we agree that process, fugitive and mobile emissions are of lower priority for reporting by general stationary combustion sources, and the regulation does not require them. ARB intends to give these sources further consideration for future reporting, particularly for industries where process emissions are significant.

C-100. Reporting Fuel Consumption from Fuel Purchase Invoices
Comment: Section 95115(a)(2)(A). Clarify regulation to make it clear that if fuel is expressed in millions Btu in fuel purchase or sales invoices that the fuel used must be converted and reported in units of scf, gallons, or metric tonnes using high heat values provided by the supplier, measured, or based on ARB defaults. [ECOTEK(30)]

Agency Response: ARB clarified that the fuel purchase or sales information is not reported directly but may be used to determine fuel consumption. We also added wording to state that the conversion from Btu to other units for facilities subject to this section of the regulation should use heat content values that are provided by the supplier, measured by the facility, or provided by ARB in Appendix A of the regulation.

C-101. Allow Use of Fuel Heat Content and Other Parameters for Alternative Fuels
Comment: Under the proposed regulation GSC facilities using alternative fuels would not have the option of reporting GHG emissions based on a calculation

of the fuel's heat content and other parameters, but would have to use CEMS. [NLA(36)]

Agency Response: Section 95115(b)(2) has been modified to allow GSC facilities to estimate emissions using specified calculation methods. These methods include using the fuel's measured heat content and other parameters, where default factors and high heat values are not available and provided in Appendix A, as with alternative fuels (now called waste-derived fuels in the regulation). The use of CEMS is not required for alternative fuels.

C-102. Provide Language to Convert Units

Comment: Propose that ARB add language that requires facilities that don't collect data with direct measuring devices or rely on purchase invoices where fuel is not in the units of scf, gallons, or metric tons, then the facility must convert to those units using high heat values provided by the fuel supplier, measured by facility, or offered as default by ARB. [ECOTEK(30)]

Agency Response: Conversion factors are provided in Appendix A to the regulation, and the commenter's suggestion has been incorporated. Though it may be obvious that a conversion is needed to apply the right default emission factor or report fuel usage in the correct units, we have added clarifying language to section 95115.

C-103. Allow Facilities To Use Default Heat Values

Comment: For the five industries for which ARB has prescribed industry specific protocols, due to the large quantities of alternative fuels potentially used at such facilities (e.g., refineries), when calculating GHG emissions, the regulations require that the heat content of alternative fuels be measured – i.e., default heat values cannot be used. For GSC facilities, however, the quantity of alternative fuels used at such facilities is likely far lower. Therefore, default heat values should be allowed. However, if ARB determines that measuring the heat values of alternative fuels is warranted for GSC facilities, NLA recommends that the frequency be at most monthly. [NLA(36)]

Agency Response: Because alternative fuels (now called waste-derived fuels in the regulation) are inherently highly variable, using "default" heat values from literature or other sources would not produce credible results. The calculation methods in the regulation will provide emission estimates that are more accurate and facility-specific than estimates that use defaults parameters. With respect to test frequency, ARB has included in the regulation language that requires measurement of heat value either monthly or upon fuel delivery, as specified by fuel type in section 95125(c). Language has also been included in section 95115(b)(2) to clarify that where default emission factors or high heat values cannot be applied, the operator has the option of testing either heat content or carbon content to calculate emissions.

D. Subarticle 3. Calculation Methods Applicable to Multiple Types of Facilities

§95125 Additional Calculation Methods – General Comments

D-1. Account for Difficulties in Measuring Solid Fuel Combustion

Comment: Page A-71, section 95125(a)-(d)(1) - ARB should be aware that precisely measuring fuel consumption for solid fuels, e.g., coal, has numerous operational difficulties. ARB might consider requiring CEMS for measuring CO_2 emissions from solid fuel combustion, or consider additional QA/QC for fuel consumption, e.g., quarterly belt or conveyor scale calibration, etc., along with hourly or daily fuel sampling and analysis. The installation of stack monitors to meet AQMD requirements should be further explored for such sources, which could allow for CEMS. [USEPA(19)]

Agency Response: We recognize that the measurement of solid fuel use poses difficulties for some facilities and fuel types. Because it is impractical to write into the regulation detailed specifications for evaluating the absolute accuracy of measurements for each solid fuel, we chose to require in section 95103(a)(9) that facility operators employ procedures to ensure a fuel activity accuracy of ±5 percent. Operators must maintain and calibrate equipment to meet this level of accuracy, and maintain appropriate records. Operators measuring solid fuels must also meet specified requirements for belt and conveyor scale calibrations and recordkeeping. ARB believes these standards will provide accurate emissions data while giving operators greater flexibility than specifying use of CEMS or detailing specific QA/QC measures for all facilities burning solid fuels.

D-2. Allow Use of Emission Factors Selected by Facility Operators

Comment: Allow facilities to select their GHG emission factors from EPA, EIA, Climate Leaders, WRI, The Climate Registry, or other sources determined to be most appropriate by reporting facilities. This will allow companies to consistently report GHG emissions across all company operations. [ACC(48)] The emission factors required to be used in the proposed regulation are different from those required to be used by U.S. EPA or the Energy Information Administration. The inconsistent data that will result will present challenges for companies and regulators attempting to address climate change issues in an integrated manner. Therefore, ARB should provide flexibility in allowing operators to choose the emission factors most appropriate to their operations as long as the factors are consistent with good engineering practice. This will allow companies to use the most appropriate factors for their operations which will result in a more consistent national and worldwide inventory of GHG emissions. [PPG(17)]

Agency Response: Under the Administrative Procedure Act, test methods, calculation procedures, and emission factors specified in the regulation must be complete at the time the regulation is adopted to facilitate full public review. To meet AB 32 requirements for rigorous and consistent emissions accounting, moreover, ARB believes we must review the factors and require they be applied uniformly where defaults are appropriate.

Allowing companies to self-select the most appropriate emission factors for their operations may result in more consistency in each company's national inventory, but it would create significant inconsistency within California. By requiring all California facilities to use the same methods and emission factors in the regulation we can help to ensure that "a tonne is a tonne" within the state. This approach will also prevent selective application of emission factors from various publications, which could be used to bias reported emission results.

Instead, ARB has attempted to specify latest available emission factors that have broad national and international acceptance for GHG emissions estimation. The factors in the final regulation also match those currently adopted by the California Climate Action Registry. We understand these factors are subject to change, and expect to revisit them in updates to the regulation.

D-3. Allow Use of Current Monitors and ASTM Methods
Comment: Facilities in California are also regulated under SO_x and NO_X Cap and Trade programs. These programs specify analytical requirements for the determination of fuel HHV and flow. Suggest that ASTM method specifications contained in the GHG Reporting Regulations are different and would necessitate additional efforts. Request that monitors maintained in accordance with manufacturer's specifications be considered adequate for the purposed of this reporting program. [CPhillips(35)]

Agency Response: ARB has attempted to select methods that are broadly accepted but rigorous, and to assure consistency in monitoring. We understand the requirements of the regulation do not always match the existing requirements for some facilities, but believe this consistency helps to ensure that all GHG data reported to the ARB have the same underlying basis. This benefits reporting facilities by preventing selective application of data or methods, which could bias results in comparison to other facility emissions. Assurance that a tonne of GHG emissions reported by one facility equals a tonne at another becomes critical in a regulatory or market framework.

§95125(b) Method for Calculating CH_4 and N_2O Emissions from Fuel Combustion Using Default Emission Factors

D-4. Allow for Use of Source Specific Emission Factors for CH_4 and N_2O
Comment: Support the ARB proposal to allow development of source-specific emission factors for CH_4 and N_2O. However, based on the typical relative magnitude of these emissions, the requirement that these emission factors be verified annually through source testing creates an unjustified cost burden for

facilities and administrative burden for ARB. Annual source testing should not be required, but instead, source testing for CH_4 and N_2O should be required no more frequently than every five years. [PPG(17)]

Agency Response: The regulation requires operators who choose to conduct source tests to develop facility-specific emission factors to conduct such tests annually, in order to account for emission sources that use highly variable fuels, such as biomass or biogas. This variability could produce significant changes in emission factors over time, which would not be known without regular source testing. Although we understand the concern about the resources involved, we believe it is necessary in the initial phases of the program to require annual testing, at least until sufficient data are available to more fully understand the variability of these emissions at each facility. Facilities that do not want to incur the costs of source testing (which is optional) may use ARB-specified emission factors based on measured or default heat content values.

ARB expects to approve source test plans in consultation with air districts, and to approve the first emission factors developed under those procedures. Tests can thereafter take place under either air district or ARB supervision. Although ARB retains the authority to review and approve emission factors developed through subsequent tests, this should be a simple matter as long as the approved test procedure has been followed. In approving emission factors developed under the first source test, ARB also has the discretion to approve in advance emission factors developed under subsequent tests that follow the same protocol, and to designate test supervision to the local air district.

With respect to timing, because operators have discretion in the choice of "best available" data and methods to apply in 2009 emissions data reports, approval of emission factors by ARB is not required. Where operators choose to verify 2009 reports, emission factor derivation would be subject to review by the verification team. Operators should request ARB approval of test plans and emission factors to be used in 2010 emission reports.

§95125(c) Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Heat Content

D-5. Lab-Based ASTM Methods for Refinery Fuel Gas

Comment: Test Methodologies. ASTM methods for the determination of refinery fuel gas HHV should be limited to laboratory based measurements (not applied to on-line analyzers which may be used to determine HHV). [WSPA(23)]

Agency Response: Wording has been added to this section such that ASTM methods refer specifically to laboratory based determinations of HHV and not on-line instrumentation.

D-6. High Heating Value Testing Standards
Comment: Recommend that an additional standard be added to the list for testing HHV for natural gas: GPA Standard 2261-90 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The newer version of this standard is GPA Standard 2261-99, and will be a Part 75 requirement for us in 2009. For oil, PG&E uses a grab sample per the ASTM D240-87 standard, not ASTM D240-02. This method is also listed in 40 CFR Part 75 (App. D Section 2.2). Section 95125(c)(1)(B) should be modified to include these standards. [PGE(13)]

Agency Response: ARB accepts these recommendations and has added GPA Standard 2261-90, GPA Standard 2261-99, and ASTM D240-87 to section 95125(c)(1)(B).

D-7. High heating value
Comment: Concern that our local gas supplier will not provide certification that they are using the methods defined in Section 95125(c)(1)(B) calculating High Heating Value of the natural gas that will essentially be used in calculating the CO_2 emissions from Redding Power. Since Redding Power uses only pipeline quality natural gas, REU recommends adding Section 95111(c)(1)(C). The section proposed would allow REU to use methods provided in section 95125(a) to calculate CO_2 emissions applying default emission factors and default heat content. [REU(18)]

Agency Response: ARB consulted with natural gas suppliers and has added language to section 95125(c)(1)(B) to include several additional methodologies for determining high heat value currently used by suppliers. As a result, high heat values from natural gas suppliers should be readily available.

§95125(e) Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Heat and Carbon Content

D-8. Calculation Error in Section 95125(e)
Comment: There is an error in the equation in section 95125(e) which results in a dimensional error. [WSPA(23)]

Agency Response: The comment is correct and the equation in section 95125(e) has been corrected.

§95125(f) Method for Calculating CO_2 Emissions from Fuel Combustion for Fuel Mixtures

D-9. Clarify Reporting of Fuel Content (mixtures)
Comment: Provide clarification of regulation language concerning reporting of emissions for fuel mixtures (section 95125(f)). The language in 95125(f) for

reporting fuel mixtures needs to be expanded to capture all of the configuration possibilities for refinery fuel gas systems. [WSPA(23)]

Agency Response: Section 95125(f) was modified to provide flexibility to address all possible refinery flue gas system configurations. The modified language provides general guidance for the reporting of refinery fuel gas fuel mixtures, rather than providing specifics for the multitude of configurations that might be encountered.

§95125(g) Method for Calculating CO_2 Emissions from Fuel Combustion Using Continuous Emissions Monitoring System

D-10. Clarify CO_2 and O_2 Measurement Requirements
Comment: Page A-78, section 95125(g)(1) - It may be better to replace the following text: "that meet the requirements of 40 CFR Part 60, may use CO_2 or O_2 concentrations and flue gas flow measurements…." with: "that meet the requirements of 40 CFR Part 60 *or Part 75*, ~~may~~ *shall* [italics need not be added] use CO_2 or O_2 concentrations and flue gas flow measurements…." If other CO_2 methodologies are allowed, it could result in conflicting CO_2 emission numbers for the same source that may be reported to different agencies under different programs. If a source has a CO_2 (or O_2) and flow CEMS installed, EPA strongly advises that source to use the CEMS data. [USEPA(19)]

Agency Response: ARB revised the regulation to include the reference to 40 CFR Part 75 as well as 40 CFR Part 60. ARB did not change "may" to "shall" in order to maintain flexibility since all sectors reference section 95125(g).

D-11. Specify Which CFR Requirements to Apply if Facility Subject to Part 60 and 75
Comment: Page A-79, section 95125(g)(6) - ARB might consider adding the following sentence to the end of (g)(6): "If both Part 60 and Part 75 requirements apply, the operator shall select and operate the added devices pursuant to the more stringent requirements." [USEPA(19)]

Agency Response: In response to U.S. EPA comment, ARB revised the regulation to read "If the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75." ARB did not use the phrase "pursuant to the more stringent requirements" because "more stringent" is not defined.

D-12. Use of O_2 Concentrations to Determine GHG Emissions from Biomass
Comment: ARB should revise 95125(g)(2) to allow using O2 concentrations based on continuous emissions monitoring system data at biomass facilities to estimate GHGs emissions as long as annual source testing demonstrates that CO2 concentrations calculated from O2 concentrations compared to measured CO2 concentrations meet the Relative Accuracy Test requirements of 40 CFR Part 60, Appendix B, Performance Specification 3. [Covanta(1)]

Agency Response: ARB agrees that the Relative Accuracy Test requirements are a reasonable basis for using O2 data to estimate CO2 emissions at biomass facilities. Also, U.S. EPA allows biomass facilities to use the O2 method under 40 CFR Part 75. ARB has revised section 95125(g)(2) accordingly.

§95125(h) Method for Calculating CO_2 Emissions from Combustion of Biomass or Municipal Solid Waste

D-13. Consider Difficulties of Fuel Consumption Measurement for Biomass and MSW
Comment: Page A-79, section 95125(h)- Measuring the amount of biomass or MSW combusted is even more challenging than for other solid fuels, like coal. Please see applicable comments under section 95125(a), (b), (d)(1)&(d)(2). [USEPA(19)]

Agency Response: Please see response to comment D-1.

D-14. Consider Incorporation of New ASTM Standard When Finalized
Comment: Page A-80, section 95125(h)(2)- When ASTM WK15321 becomes a final ASTM standard, ARB may want to reference it to better ensure that a representative sample of source emissions is obtained for determining biomass-derived CO_2. [USEPA(19)]

Agency Response: Although we cannot incorporate an ASTM that is not final, we intend to update the regulation on a regular basis to incorporate new methods and reporting requirements as needed.

Comments were not received specific to the following sections:

§95125(a	Method for Calculating CO_2 Emissions from Fuel Combustion Using Default Emission Factors and Default Heat Content
§95125(d)	Method for Calculating CO_2 emissions from Fuel Combustion Using Measured Carbon Content
§95125(i)	Method for Calculating Mobile Combustion Emissions
§95125(j)	Method for Calculating Fugitive CH_4 Emissions from Coal Storage
§95125(k)	Method for Calculating Indirect Electricity Usage
§95125(l)	Method for Calculating Indirect Thermal Energy Usage

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

E-1. Verification – Provide Self-Verification
Comment: Support self-verification by facility operators. There should be uniform rules and compliance for all verifiers. Do not support the concept of air districts being the sole verifiers. [AB32IG(47)]

Agency Response: The regulation requires all verifiers to meet the same qualifications to become accredited and perform the same duties in verifying emissions reports. The regulation allows facility operators to select private third party contractors or participating air districts for verification of their emissions reports. Regarding self-verification, having an independent third party evaluate the completeness of emission reports and compliance with reporting requirements substantially enhances the value and credibility of submitted emissions reports. Experience with both voluntary and mandatory GHG reporting programs shows that errors are quite common in the development of GHG inventories. In the future there could be a marketplace for the trading of carbon emissions credits; therefore, it is particularly important to remove any appearance of conflict of interest that would arise with facility operators verifying their own emissions reports.

E-2. Delete Requirements for Verification
Comment: The regulatory requirement that the reporter must submit a signed and dated statement stating that "the statements and information contained in the emissions report are true and accurate to the best knowledge and belief of the certifying official," should be sufficient for verification purposes. Request deletion of the whole section that requires GHG emissions verification by third parties. [Praxair(22)] The requirement for mandatory third party verification of emissions data is unnecessary and will increase industry compliance costs with little, or no tangible benefit to ARB. [CLFP(10)]

Agency Response: Third party verification is a cornerstone of national and international GHG reporting protocols (e.g. The California Climate Action Registry and the EU ETS). Third party verification is required to insure the integrity, accuracy and transparency essential to the implementation of mandatory GHG reporting under AB32. Also see response to comment E-3.

E-3. Third Party Verification is Unnecessary and Costly
Comment: The third party verification requirement for small businesses is unnecessary and costly. CARB has not required verification of other data reported to the local air district. [MKP(45)]

Agency Response: Criteria pollutant data reported to local air districts is measured using standardized equipment with standardized operating procedures and monitoring equipment audits. In general, GHG emissions are calculated from fuel and other data and not directly measured. Some of the methods for calculating GHG emissions can be complex and potentially subject to reporting errors. Third-party verification provides an independent evaluation of the GHG calculation process and helps to ensure all specified methods are complied with in calculating GHG emissions. ARB performed a cost analysis as part of the rulemaking process. The verification costs were determined to be relatively minor for the types and sizes of the facilities subject to the regulation. Also see response to comments E-1 and E-2.

E-4. Delete Requirement for Third Party Verification or Modify Requirements
Comment: Delete the whole section that requires GHG emissions verification by third parties. If the Preferred Change mentioned above is not implemented we suggest the following to minimize the burden: a) Place hydrogen plants into a triennial schedule in section 95103(c)(2) for verification; and, b) As required in 95103(c) change the time from when verification for existing facilities is required from 2010 until 2012 to allow for more time for the verification process to be fully developed and implemented. [Praxair(22)]

Agency Response: Third party verification is standard international practice and allows for a credible, rigorous GHG emissions reporting program. Experience in the voluntary registry has shown that error often enters into the calculation and reporting of GHG emissions. Hydrogen plants are considered a critical partner for most oil refineries in the state. As a specific sector, they are required to have annual verification. ARB is currently developing the verification program and expects it to be fully operational in 2009. In approving the regulation, the Board made it clear that all facilities should be subject to verification beginning in 2010 to ensure emissions data is as accurate and credible as possible from the outset.

E-5. Waive Third Party Verification Based on Fuel Used
Comment: Waive mandatory third-party verification if 90 per cent or more of a facility's emissions are from fossil fuel combustion. [CLFP(10)]

Agency Response: Third party verification is essential to assuring the accuracy of emissions data reported under the regulation. Though measurement of some fossil fuels may be less subject to error, all fossil fuel GHG emissions are of great concern as a matter of science and policy. Issues of inventorying all applicable sources, using the correct emission factors, and accuracy of fuel measurement still need to be addressed. Third-party verification ensures that all of these are subject to an independent review. Removing the verification requirement for operators that use mostly fossil fuel may also discourage the use of renewable or alternative fuels.

E-6. Require Third Party Verification
Comment: Require third party verification for all emission reports. [NRDC(15)]
Support for verification provisions of regulation. [APC(41)]

Agency Response: Under the proposed regulation, facility emission reports are subject to third party verification. Most complex and high-emitting facilities and entities are subject to annual verification. Specified types of facilities, which are smaller or have more stable and less complex emissions to report, are permitted to forgo the less intensive interim year verifications between the full verifications that are required of all facilities triennially. We believe this it the correct balance of ensuring the accuracy and completeness of submitted data, while minimizing regulatory costs and burdens.

E-7. Access to Sufficient Number of Qualified Verification Bodies

Comment: Understand and support the need for independent verification. However, we do have a concern that there will be adequate access to a variety of qualified verification bodies. Part of this is ensuring that all verification bodies, whether air districts or private, must meet the same training and qualification standards. [CPhillips(35)] Concern that even with staggered reporting and verification deadlines; there will not be an ample pool of verifiers. ARB should continue to emphasize verifier training for the next few years and also look to streamline verification requirements to reduce the reporting burden on regulated entities. [ACC(48)]

Agency Response: The regulation requires that all air districts or private entities meet similar accreditation requirements to provide verification services. ARB is committed to conducting verifier training to ensure that there is an ample pool of verifiers. We anticipate a large demand for verifier training and will continue to offer the training as needed. ARB will also continue to look for opportunities to revise and streamline the verification process as part of future amendments to the regulation to balance the needs of a rigorous verification process with the desire to reduce the reporting burden on reporting facilities.

E-8. Keep Verification Program Control at State Level; Air Districts as Verifiers

Comment: Recommend that the verification program be structured and controlled at the state level, and be consistent with applicable ISO standards, such as ISO 14064-3 and 14065. In no case should the program be perceived as having a conflict between regulatory enforcement activity and commercial third party verification, as is practiced around the world. Concern that the use of air districts as verifiers will stifle the flow of information necessary for conducting verification. [API(12)]

Agency Response: The proposed regulation calls for GHG verification to be structured and implemented at the state level. ARB has made significant effort to ensure that the structure of verification procedures in this regulation is consistent with international protocols. Air districts will have the opportunity to provide verification services; however, they will not be sole verifiers and will be required to meet the same standards as commercial verifiers.

During the rulemaking process some stakeholders expressed a desire for air districts as verifiers while others clearly preferred private consultants. ARB decided either was acceptable as long as training is consistent and financial and personal conflict of interest can be avoided. Under the regulation both air districts and private third parties are required to have “policies and mechanisms in place to prevent conflicts of interest and resolve potential conflicts of interest if they arise."

E-9. ARB Should Implement Annual Verification by Random Sampling
Comment: Large investor-owned utility (IOU) retail providers such as SCE typically enter into thousands of wholesale electricity market transactions every year. SCE believes that it would be an unproductive use of both IOU and third party verifier resources to review all of these transactions in order to verify compliance with ARB's reporting requirements. Random sampling would allow for verification of retail provider reports without an unduly burdensome and unnecessary review of thousands of wholesale electricity market transactions. [SCE(16)]

Agency Response: This concern is already addressed through the regulation's use of internationally accepted GHG verification principles. A verifier does not rebuild the inventory during verification, but employs random sampling of reported data for data checks while also focusing on areas of highest emissions and highest uncertainty in calculation or reporting of those emissions. See section 95131(b)(8)-(9) of the regulation.

E-10. Provide Audit Plan for Verification
Comment: When staff returns to the Board with regulation amendments, they should provide the Board with an audit plan for verification. [SCAQMD(T10)]

Agency Response: Staff will develop an audit plan to help ensure a rigorous and credible GHG emissions reporting and verification program. That audit plan is not part of the regulation itself, however.

§95130 Requirements for Verification of Emissions Data Reports

Comments were not received specific to this section.

§95131 Requirements for Verification Services

E-11. Clarification for Accredited ARB Specialist for Utilities/Cogen
Comment: For 95131(a)(2)(A): To clarify the requirement for an accredited ARB specialist for electric utilities and cogeneration facilities, I recommend replacing the concept of an "electricity transaction specialists" with the following language: "...accredited by ARB as an electric utility and cogeneration transaction specialist." Previous wording was unclear and did not include cogeneration. [APC(8)]

Agency Response: Section 95131(a)(2)(A) is specific to providing verification services to a retail provider or marketer. The regulation does not require specialist team members for electric generation and cogeneration facilities.

E-12. Clarifications to Requirements for Verification Services Text

Comment: Recommend changes to section 95131(c)(3) to provide time prior to submittal of an adverse opinion to ARB for operator modification of an emissions data report. Alter wording of section 95131(c)(3)(B) to have the Executive Officer provide the necessary guidance to the operator and verification body on how to proceed to complete a positive verification under the circumstances. [WSPA(23)]

Agency Response: ARB agrees that time should be provided for operator correction of a report that would result in an adverse opinion and has made this change at section 95131(c)(3). We do not support the second recommendation, which could result in frequent and unnecessary appeals to the Executive Officer. The regulation specifies the methods and calculations to develop an emissions report, and it is up to the verifier to make an objective determination as to whether the methods were followed and the calculations done correctly. Allowing for the opportunity to provide emissions data based on alternative methods would provide an opportunity for less rigor and standardization in the emissions reports and a path to circumvent the specific requirements of the regulation.

E-13. Verification Site Visits Could be Onerous for Multiple Facilities

Comment: 95131 (b)(4) Verification requires a site visit to each facility every 3 years. For a company with many similar facilities, like Calpine which has 41, the requirement is onerous. Calpine recommends that a sampling/percentage of each type of facility be visited each three year reporting cycle. [Calpine(24)]

Agency Response: ARB understands Board direction to require fully verified 2010 emissions reports, which may be used to make key decisions in 2011. Because site visits are important to assuring that all sources have been identified, we are unable to accept the request for staggering a sampling of facilities for site visits at this time. To address cost concerns in part, ARB has modified the regulation to remove the requirement for interim year verifications at geothermal, biomass, and small (<10 MW) generating facilities.

E-14. Clarifications to Verification Requirements

Comment: Section 95131(b)(4)(A): Recommend changing the word “ensure” to “check.” The word “ensure” implies absolute identification of all sources, great or small. A verification body that would meet the requirement to “ensure” with reasonable assurance would have to increase its on-site verification time to levels that the ARB likely does not intend. We recommend in the second line changing the term “accounted for” to “identified.” The former term implies quantification, the latter term implies inclusion of the source in the inventory. It is the responsibility of the verifier to reach a conclusion concerning the completeness of the emissions sources reported by the operator. It is the responsibility of the operator to quantify emissions, or “account for,” those sources. A site visit is an important part of verification because it provides a verification body the opportunity to assess, on a sampling basis, the operator's complete identification of sources. [NSFISR(32)]

Agency Response: ARB agrees and has made these changes.

E-15. Clarification to Verification Requirements
Comment: Section 95131(b)(8) Sampling Plan: Recommend changing the word "all" in line 4 to "the". For the verification team to review "all inputs for the development of the submitted emissions data report" implies 100% sampling, which would be prohibitively expensive, contrary to the spirit of ISO 14064-3, and likely not the intention of the ARB. [NSFISR(32)]

Agency Response: ARB agrees and has made this change.

E-16. Question About Documentation Requirements
Comment: Section 95131(b)(8)(B): We are puzzled by this requirement. It has no obvious parallel to the GHG verification approach described in ISO 14064-3, and appears to be of limited utility. The operator's submitted emissions data report should already provide the verification team with quantified emissions data in listed form. Normal practice is for the verification team to review the operator's submitted report during a document review phase of the verification, and develop a verification plan taking into account risk to material misstatement. This usually means selecting for verification those sources that have the highest reported emissions. We believe it is unnecessary and duplicative to require the verification team to establish a rank order list in the sampling plan. Instead, the sampling plan should focus verification resources on the emissions sources that the verification team has determined have the highest potential for material misstatement. We note that the information about electricity transactions is repeated in 95131(b)(9)(B) and does not need to be retained here. We recommend that this paragraph be deleted. [NSFISR(32)]

Agency Response: This documentation requirement is applied to verification services to establish a record that ARB can review as part of its audit process. The regulation specifies products such as this one to ensure that there is no confusion as to the minimum number of tasks a verifier is to perform during verification. Consequently, no change has been made. Regarding the comment about duplication in section 95131(b)(8)(B) and 95131(b)(9)(B), 95131(b)(8)(B) addresses the ranking of emissions sources for verification, and 95131(b)(9)(B) addresses the data checks to be performed on the selected sources from among those ranked. These sections are not duplicative and both need to be retained, so no change was made.

E-17. Recommend Changing Sampling Plan Requirements
Comment: Section 95131(b)(8)(C): Propose (changing) the language of the first three lines of this paragraph to the following: "The verification team shall base its sampling plan upon a qualitative assessment of the risk to fair reporting of

emissions based upon an examination of evidence pertaining to the following areas as applicable under the sections 95110 to 95115." [NSFISR(32)]

Agency Response: The existing requirement clearly outlines the key areas of risk assessment that must be addressed in providing verification services. The regulation requires this level of detail even though there is a general understanding in GHG verification practices of how to approach risk assessment. The current language provides the minimum areas to be addressed in risk assessment for the sampling plan, in ARB's opinion. Consequently no change has been made.

E-18. Text Clarification
Comment: Section 95131(b)(9)(B), line 3: Recommend changing the word "uncertainty" to "material misstatement." [NSFISR(32)]

Agency Response: ARB agrees and has made the appropriate change.

E-19. Remove Requirement for Submitting Sampling Plan and Data Checks
Comment: Section 95131 (c)(2)(A), lines 3-4: Recommend deleting the "sampling plan" and the "detailed comparison of the data checks with the emissions data report" from the information submitted with the verification report. It is normal international practice for sampling plans to remain part of the confidential working papers of the verification body. Sampling plans normally are not provided to the audited organization, because they communicate the verification team's strategy for gaining the confidence necessary to achieve reasonable assurance. Verification plans, on the other hand, divulge in general terms what the verification team plans to examine without signaling in detail the extent of examination necessary to achieve reasonable assurance.

"The "detailed comparison of the data checks with the emissions data report" normally form part of a verification team's confidential working papers. They are reviewed internally within the verification body but are not shared with the audited organization. There are at least two reasons for this. First, the format of verification working papers may be proprietary to the verification body, and disclosure to the audited organization breaks the confidentiality of methods and could become available during document review to any successor verification body after the expiration of the six-year limit on verifying a single operator. Second, the information in the working papers may include evidence meaningful to the verification team and independent reviewer, but not constitute "detailed comparison of the data checks with the emissions data report." Verifiers tend to rely on recorded information ("detailed data") provided by the audited organization and may make notes on copies of such records concerning a verification method employed and its general outcome. Requiring verifiers to append to verification reports "detailed comparison of the data checks with the emissions data report" is therefore a burdensome paperwork requirement that adds no apparent value to the verification service and takes time away from more meaningful verification activities. [NSFISR(32)]

Agency Response: ARB agrees that sampling plans should remain with the verification bodies and has made this change. ARB does not agree that comparisons of data checks should be left out of verification reports. The level of data check detail in the verification reports can be limited to the emissions for the discrete data sampled, not the methods for recalculation of those sampled data. ARB does not perceive this as a burden, but a key component for providing a complete and auditable verification report.

E-20. Non-substantial Text Edit
Comment: Section 95131(c)(2)(A), line 4: Recommend substituting the word “a” for “the” before the term “issues log.” [NSFISR(32)]

Agency Response: ARB intends to refer to the log of issues specified in section 95131(b)(11). We have not made the recommended change but have made the term consistent.

§95132 Accreditation Requirements for Verifiers

E-21. Standardize Requirements for Verifier Accreditation
Comment: All verifiers, including the districts, should meet the same standards. [WSPA(23)]

Agency Response: ARB agrees and the regulation already reflects this requirement.

E-22. All Verifiers Should Meet the Same Standards.
Comment: Air districts should not be precluded from offering verification services, but should not be sole verifiers. Attachment C of the submitted comments provides suggestions. [WSPA(23)]

Agency Response: Air Districts will have the opportunity to provide verification services, but will not be sole verifiers.

E-23. Edit to Verification Body Definition
Comment: Section 95102 (a)(186): Restate as ““Verification body” means a firm or AQMD/APCD, accredited by ARB, that is able to render a verification opinion and provide verification services for operators subject to reporting under this article. [WSPA(23)]

Agency Response: This change was made.

E-24. Increase Professional Liability Coverage Requirement

Comment: Section 95132(b)(1)(C), line 2: Recommend changing “one million” to “ten million”. Verification of GHG emissions reports should be conducted by verification bodies with substantial enough resources and professional liability to cover the consequences of significant errors and omissions. Professional liability coverage, as opposed to general business liability insurance, is typically underwritten for a minimum of $5 million. We believe the importance of this activity warrants setting required levels of professional liability above customary minimums. [NSFISR(32)]

Agency Response: The current regulation only requires the reporting of GHG emissions and one million dollars is sufficient to reflect the value of those services. If in the future a monetary value is associated with GHG emissions, the verification program liability requirements may be altered to address the change in values associated with emission reports.

E-25. Non-Substantial Text Edit
Comment: Section 95132(b)(1)(D)(1), line 2: Recommend deleting “and customers.” [NSFISR(32)]

Agency Response: ARB agrees that the types of customers are sufficient without requiring the names of all of the customers a verification body has served. Conflict of interest is handled on a case by case basis before verification services may be provided where a detail of any prior relationship between a verification body and operator is documented. ARB has made the appropriate change.

E-26. Non-Substantial Text Edit
Comment: Re section 95132(b)(1)(D)(2), lines 2-4: “We recommend ending this sentence in the second line after the word “entities”. The remainder of this sentence is duplicative of the requirement in (b)(1)(D)(1).” [NSFISR(32)]

Agency Response: ARB agrees and has made the appropriate change.

E-27. Use of Accreditation versus Certification Terminology
Comment: Throughout most of the regulation, recommend changing the term “accreditation” to “certification” and “accredited” to “certified.” This change will promote consistency with national and international uses of the terms “accreditation” and “certification.” [NSFISR(32)]

Agency Response: Please see response to comment B-16.

E-28. Text Edit for Clarification
Comment: Section 95132(b)(2)(A): Recommend changing the lead-in paragraph to (b)(2)(A)1-3 because the references cited in (b)(2)(A)(2) and (b)(2)(A)(3) are not, properly speaking, “greenhouse gas reporting programs.” We propose that

this sentence read: Evidence that the applicant has demonstrated experience as a lead greenhouse gas verifier by one of the following methods: [NSFISR(32)]

Agency Response: ARB believes the provision is clear as drafted and rejects the recommended change as unnecessary.

E-29. Text Clarification for Grandfathering
Comment: Section 95132(b)(2)(A): Propose adding, on a separate line following (b)(2)(A)(3), the word "Or." If the word "Or" is not added at the end of the entirety of (b)(2)(A), no GHG verifier who did not meet one of the three types of "grandfathering" experience cited in (b)(2)(A) could ever submit sufficiently complete evidence to the Executive Director to become certified. We do not believe this is ARB's intention. [NSFISR(32)]

Agency Response: ARB agrees and has made the appropriate change.

E-30. Text Clarification
Comment: Section 95132(b)(2)(A)(1): Recommend adding to the beginning of this sentence the word "Serving" and changing the word "registered" to "approved". To our knowledge, CCAR has only conducted a review and approval process for proposed verification body staff. [NSFISR(32)]

Agency Response: ARB agrees that the California Climate Action Registry did not register lead verifiers but worked with the California Energy Commissions to approve lead verifiers, therefore 'registered' has been changed to 'approved.' The word 'serving' was not added to the beginning of 95132(b)(2)(A)(1) because 95132(b)(1)(A) introduces this requirement and contains the phrase 'acted.' To add 'serving' would be duplicative of language already stated preceeding this section.

E-31. Text Clarification
Comment: Section 95132(b)(2)(A)(2): To improve accuracy, recommend adding to the beginning of this sentence the word "Serving" and then continuing with "As a lead verifier who has performed at least three verifications by December 31,2007 and who has been witnessed in that capacity by the United Kingdom Accreditation Service with favorable assessment of services performed. [NSFISR(32)]

Agency Response: ARB believes the provision is clear as drafted and rejects the recommended change as unnecessary.

E-32. Text Clarification
Comment: Section 95132(b)(2)(A)(3): Recommend this sentence be modified to read as follows: "Is certified by a body operating personnel certification in accordance with the requirements of ISO 17024:2003 or equivalent as having met competency requirements for greenhouse gas verifiers defined in

ISO 14065, or as having met competency requirements for environmental management systems auditor as defined in ISO 19011, and who has performed at least three verifications by December 31, 2007. [NSFISR(32)]

Agency Response: ARB agrees ISO 14064 is not relevant to the requirements of a verification body, but to the verification process itself and has removed this reference. The reference to ISO 17024 was not included because it could potentially limit the acknowledgment of accreditation programs that are just as rigorous as any programs developed under an ISO 17024 requirement. ARB has provided a mechanism to accredit individuals and it does not operate under ISO 17024. ARB believes that the regulation is clear and did not make any further suggested changes.

E-33. Reduce Verifier Requirements

Comment: Section 95132(b)(2)(B): Recommend substituting “at least four completed verifications” for “two continuous years” in line 2 and substituting “and has been witnessed as an acting lead verifier under the supervision of an ARB [certified] lead verifier in at least one completed verification” for “has worked as a verifier in at least three completed verifications under the supervision of an ARB [certified] lead verifier”. We make this recommendation because the length of time that an individual holds a particular certification does not guarantee that the verifier will either use that qualification or be successful at performing the service. In our opinion, it is more appropriate for an experienced-based qualification to make reference to verifications completed than time in grade. [NSFISR(32)]

Agency Response: ARB did not make these changes. ARB believes that the current requirements for both the length of previous experience combined with the number of verifications will result in better quality of emissions verifications. The approach will also avoid a rush for individuals to get the minimum number of verifications in any one calendar year. Regarding the suggestion to include the text “witnessed as an acting lead verifier…,” ARB did not implement this approach because it would create an unnecessary subcategory of an “acting lead verifier” and defining appropriate requirements for qualifying “acting lead verifiers” would be necessary, without a commensurate benefit. The current approach also provides ARB the more flexibility in arranging opportunities to audit the individuals, as required, to be reclassified as a lead verifier.

E-34. Modify Language Related to Subcontracting

Comment: For section 95132(e)(2), now renumbered as 95132(e)(3), recommend that the paragraph be renamed “Subcontracting and Outsourcing.” Recommend the first line of this subparagraph be amended to read “A verification body shall not include verifiers employed or subcontracted by verification bodies to which it has outsourced verification services among the number used to meet the minimum staff total.” Common industry practice is to directly employ management and support staff but to subcontract for auditors. [NSFISR(32)]

Agency Response: ARB appreciates the suggested wording but does not support a change to the basic requirement that at least five persons be directly employed by the verification body, including at least two lead verifiers, to meet the requirements of section 95132(b)(1)(A). We believe this requirement will provide stability and accountability to the verification industry in California.

§95133 Conflict of Interest Requirements for Verifiers

E-35. Verifier Conflict of Interest Requirements are Inadequate

Comment: While having a third party verifier can provide important expertise to companies doing their emissions estimates, conflict of interest limits for the verifiers in the proposed regulation are weak. After being questioned by a consulting company, ARB stated in the public workshop that it envisions allowing large consulting companies with existing contracts with a polluting facility to still provide third party verification, as long the company provides a different individual for the GHG verification within the company. It appears that ARB's statements mean that a huge consulting company with a large financial interest in and long history of being hired by and defending a polluting company's interest (usually known as a hired gun) could probably still provide one of its individual consultants as an impartial third party verifier as long as the individual did not previously do GHG emissions inventories for the company. Especially in such cases, the data underlying the emissions inventory must be made available to the public and not kept secret. [CBE(21)]

Agency Response: Every proposed verification arrangement will be reviewed for conflict of interest. Where within the previous three years any member of the verification body (or related entity including subcontractors) has provided to the operator any of sixteen specified non-verification services, the potential for conflict of interest is deemed high and the operator must find another verification body. In addition, conflict of interest potential may be deemed low only when any non-verification services provided within the previous three years are valued at less than 20 percent of the proposed verification fee. Where a medium potential for conflict is found, the verification body must submit a plan to avoid, neutralize or mitigate any conflict; this plan must meet three additional specifications. The regulation's conflict of interest provisions, based on financial auditing practices and guidelines in other GHG reporting programs, are designed to prevent the occurrence of situations such as the one given in the commenter's example. ARB feels these rules and ARB oversight will provide for the credible and independent verification of reported GHG emissions.

E-36. Change Conflict of Interest Requirement

Comment: For section 95133(c) recommend modifying requirement by ending it after "95133(b)" in line 2 and deleting the remainder of the text in the sentence. Believe that permitting the verification body to have engaged in any amount of work described in 95133(b) during the previous three years should create a conflict-of-interest that would preclude it from providing the verification service. [NSFISR(32)]

Agency Response: ARB is concerned that given the relative infancy of GHG verification services in the United States there is little chance that enough 'pure' GHG verification bodies will be available to meet the need of our reporters. We believe that the regulation's constraints on the types of additional services that may be provided and the limitation on their monetary value provide a strong enough safeguard against potential conflicts of interest, and consequently decline to make the suggested change.

E-37. Text Edit
Comment: In section 95133(e) recommend changing the word "Verifiers" in the title to "Verification Bodies." [NSFISR(32)]

Agency Response: ARB agrees and has made the appropriate change.

F. Appendix A. ARB Compendium of Emission Factors and Methods to Support MandatoryReporting of Greenhouse Gas Emissions

F-1. Use GWPs from 2nd Assessment Report
Comment: Staff Report page 54. Support the use of GWPs from the IPCC Second Assessment Report. [USEPA(19)]

Agency Response: The regulation continues to reflect this recommendation in section 95103(a)(6) and in Table 2 of Appendix A.

F-2. Update Coal Storage and Handling Emission Factors with Newer Data
Comment: ARB Compendium of Emission Factors
Page Appendix A-13- Table 10 references a 1999 EPA/STAPPA/ALAPCO report that provides default emissions factors for post mining coal storage and handling. The Inventory of U.S. GHG Emissions and Sinks uses updated values that provide greater regional disaggregation. Suggest applying these new factors to the regulation. [USEPA(19)]

Agency Response: The emission factors in the proposed regulation were based on historical U.S. EPA default emission factors. ARB has revised the regulation to reflect the updated U.S. EPA factors.

F-3. Include Pound to Kilogram Conversions in the Appendix A Example Form
Comment: Staff Report page A-48, section 95111(g)-(h) - The proposed regulatory text requires operators to convert pounds to kilograms. This is a reasonable requirement, but it should be reinforced by making parallel changes to the sample emissions reporting form in Appendix A. Otherwise, the different units in the form and in the regulatory text will be a source of confusion. (If

requested, EPA can provide a draft form that provided a conversion from pounds to kilograms at the end.) [USEPA(19)]

Agency Response: We have updated the Appendix A emissions estimation form for SF_6 to make the conversion from pounds to kilograms an explicit requirement.

F-4. Add Additional Emission Factors for N_2O
Comment: In addition to the N_2O emission factors provided in Table 6 of Appendix A, it is recommended that ARB provide additional N_2O emission factors for different source categories and equipment types to account for the substantial variability in these emissions. [STI(38)]

Agency Response: Limited N_2O emission factor data are available, so it was not possible to include the source-specific emission factors requested. In most cases the default emission factors will be adequate for typical facility operators to obtain accurate emission estimates. In a case where the facility operator believes that application of the supplied emission factors are not appropriate, the operator has the option to conduct a source test their specific emissions sources and develop N_2O emissions estimates from these facility test data (section 95125(b)(4)).

F-5. Geothermal Facilities Emission Factor
Comment: Despite corrections to the emission factor for CO_2 emissions from geothermal facilities, the equation will continue to result in an unrealistically high CO_2 level that does not accurately reflect the actual emissions associated with electricity generated by the facility. [NCPA(BH2)]

Agency Response: The emission factor in the proposed regulation for geothermal facilities was reduced from 16.6 to 7.53 kg CO2/MMBtu to correct a typographical error. The source of the factor is the Energy Information Administration. ARB used this emissions factor to calculate geothermal emissions in ARB's greenhouse gas emissions inventory. In response to comments from California geothermal facility operators, ARB added language to the proposed reporting regulation to allow operators to develop their own site-specific emission factor to better represent emissions from their facilities. Since the first year of reporting will be based on best available information, time is allowed for ARB to work with geothermal operators to develop their site specific emission factors and test the methodology.

G. Other 45-Day Comments Received

G-1. Update ARB Protocols as Needed for CCAR & TCR Consistency
Comment: ARB protocols should change as needed to maintain consistency with CCAR and TCR reporting tools. [CPhillips(35)]

Agency Response: Throughout the regulation development process, ARB worked to maintain a level of consistency between the mandatory AB 32 GHG reporting methodologies and methods found in CCAR voluntary reporting protocols. Where differences occur they are usually due to other requirements of the Act and California regulatory law, the need to develop new methodologies to support reporting for sources not addressed in the CCAR protocols, and recommendations made in the public process. In some cases ARB chose a method for inclusion in the regulation from among several choices in the CCAR protocols, to assure the consistency and rigor required of mandatory reporting programs. Emissions reports generated under the mandatory reporting program must be sufficiently accurate to support California's greenhouse gas control strategies, including likely future market-based approaches. Facilities subject to regulation also want assurance that tonnes will be equivalent within their sectors.

G-2. Effects of Regulation on CCAR Members

Comment: How will the regulation affect members of the California Climate Action Registry (CCAR) unable to meet the 12/31/2006 deadline? ARB should consider defining a timeline for those members who are able to have their emissions verified with 30 or 60 days of the deadline. [Raytheon(29)]

Agency Response: ARB does not have discretion to change dates specified in the Act (Section 38530(b)(3)), and the regulation does not exempt CCAR members from reporting their GHG emissions to the ARB or provide different reporting protocols for CCAR members. Therefore, implementing the suggestion would have no effect on the reporting requirements for facility operators. In developing the regulation ARB worked to meet Act requirements to incorporate CCAR standards (e.g., third-party verification) and protocols (e.g. methods in the cement, electricity generation, cogeneration and general stationary combustion sectors) where feasible and appropriate. It was necessary to vary from the voluntary program in a number of cases to ensure the mandatory reporting program is rigorous and consistent, as also required by the Act. Also see response to comment G-1.

G-3. Request that Reporting Requirements be Consistent for All GHG Reporting

Comment: To reduce reporting burdens it is important that reporting be consistent for The Climate Registry, the Chicago Climate Change, the California Climate Action Registry, and the WRI Greenhouse Gas Protocol. This consistency is particularly important for facilities that operate a large number of facilities across the United States. Also, seamless transfer of data between GHG registries should be provided. [AAC(48)] Make the California reporting requirements as consistent as possible with the reporting requirements of other regional and national reporting organizations including CCAR and The Climate Registry. [WM(T14)]

Agency Response: In developing the first comprehensive mandatory GHG reporting program in the United States, ARB worked to ensure consistency to the extent possible with existing voluntary protocols. To ensure the rigor, consistency and enforceability required of a mandatory program, however, the regulation does not provide the wide range of reporting flexibility often present in those programs. Staff had to choose from and sometimes augment quantification methods found in the other programs. In addition, under the California Administrative Procedures Act staff had to propose clearly defined and specific emission estimation methods and reporting requirements. Finally, because some of the GHG registries mentioned in the comment are themselves in a state of development and flux, it was not feasible to achieve full consistency among all reporting programs. Nonetheless, ARB will continue to collaborate and consult with the Western Climate Initiative, U.S. EPA, The Climate Registry, CCAR, and others, to help minimize duplication of effort and inconsistencies in GHG reporting where possible.

G-4. Integrate Reporting of GHGs, Criteria Pollutants, and Toxics

Comment: Provide consolidated reporting for GHG, criteria, and toxic emissions to streamline reporting and improve data quality. [ECOTEK(30)]

Agency Response: Due to significantly different reporting needs and regulatory requirements, it is not possible at this time to integrate the reporting of GHG, criteria, and toxics emissions. For GHG emissions it is necessary to provide statewide consistency in emissions calculation and reporting methods that are not always present for the other pollutants. GHG emissions have global rather than local impacts, and the Act required ARB to enact a State reporting program. Reporting is appropriately directed to air districts for the other pollutants, where impacts are local or regional. Developing a consolidated emissions reporting system will require substantial modifications to existing reporting systems and practices, which cannot be implemented in the near term.

G-5. GHG Reporting and Verification Should Be Done by Air Districts

Comment: GHG reporting and verification should be conducted through the local air districts. [BAAQMD(BH7)]

Agency Response: The Act requires a statewide GHG reporting and verification program. This is appropriate for pollutants of global concern where consistency is critical, and makes it practical to coordinate GHG emissions and market data with other states on regional or national scales. Most other states do not have local air districts and will be coordinating reporting and verification at a state level as well. Also see response to comment G-7.

G-6. Include Districts in GHG Data Collection

Comment: Districts can play an invaluable role in the collecting of GHG emissions data. [BAAQMD(T11), CAPCOA(T12), ALA(T22)] Request that GHG reports be submitted to the local AQMD, using ARB specified methods, as part of the facilities AQMD Annual Emission Statement. [MKP(45), CAPCOA(T12)] Reporting systems should be non-duplicative with district systems and that the proposal to allow dual reporting does that and is efficient. ARB and districts should work together on reporting. [SJVUAPCD(T5)] Include air districts in the inventory and reporting of GHG emissions. [BAAQMD(T11)]

Agency Response: We expect and hope local air districts will be involved with various aspects of the GHG reporting regulation, including source testing and the identification of applicable facilities. However, the Act calls for a state-level GHG reporting and verification program and requires the ARB to promote consistency between the California program and other international, federal, and state reporting programs. Only through a unified and consistent state-level reporting program is it practical to coordinate California GHG emissions and market data with other programs. Using air districts with differing reporting requirements, schedules, data submittal systems, and protocols would inevitably lead to inconsistencies that may reduce the effectiveness of California's aggressive GHG emission reduction efforts.

G-7. Submit GHG Data to Local Air Districts

Comment: The Bay Area and South Coast Air Quality Management Districts are already set up to evaluate CO_2 and methane emissions -- we support the idea that these Air Districts would handle GHG reporting through submissions to them. This would address the problem that ARB has identified concerning ARB not having sufficient resources to keep the entire database in-house. Since these local Districts already keep inventories of criteria pollutants, they need only add pollutants to existing inventories…This would also house the calculations forming the basis of the data in a public agency rather than housing the calculations within each separate company. [CBE(21,T6)]

Agency Response: The Act requires a GHG reporting and verification program with statewide consistency and rigor. California's 35 air districts often have very different reporting frameworks and requirements, and it would not be possible to assure this a consistent and equally rigorous application of GHG reporting requirements outside of a statewide program. There is also extensive non-emissions data to be collected, including wholesale and retail electric power transactions. These data are already highly complex on a statewide basis and may be impossible to parse out by air district.

ARB has sufficient resources to administer a statewide program. Submitted data will be maintained by the ARB, a public agency that is required by law to provide emissions data to the public. ARB also will have full access to the calculations that undergird reported emissions. Also see the response to comment G-6.

G-8. Emissions Should be Estimated from Upstream Sources

Comment: Emissions form combustion sources and energy end users can be determined from energy and fuel providers. There is no need or requirement for individual facilities to report their emissions to determine statewide greenhouse gas emissions and meet the requirements of AB 32. [NUMMI(34), NUMMI2(T9)]

Agency Response: We disagree with the interpretation of the commenter. The Act requires ARB to adopt a regulation to "require the monitoring and annual reporting of greenhouse gas emissions from greenhouse gas emission sources beginning with the sources or categories of sources that contribute the most to statewide emissions." The Act defines a "greenhouse emissions source" as "any source, or category of sources, of greenhouse gas emission whose emissions are at a level of significance, as determined by the state board, that its participation in the program established under this division will enable the state board to effectively reduce greenhouse gas emissions and monitor compliance with the statewide greenhouse gas emissions limit."

Limiting emissions reporting to upstream sources would be ineffective for achieving reductions and monitoring compliance with regulations. Only through the GHG reporting by individual facilities, which will have the responsibility for emissions reductions, will we be able to track, verify, and monitor GHG reductions. Whereas the commenter emphasizes the "statewide" component of the reporting, and the desire to avoid individual facility reporting, this approach would clearly not support the efforts of the ARB or the State in meeting our GHG reduction requirements.

G-9. Inconsistencies Between 1990 Emissions and Current Reporting
Comment: The methods used to compute current year emissions must be consistent with those used to compute 1990 emissions. Because the 1990 estimates are mainly based on upstream fuel usage, the current estimates should use a similar approach, which is sufficient for determining statewide GHG emissions. [NUMMI(34), NUMMI2(T9)]

Agency Response: ARB does not agree. We recognize that the methods used to compute the 1990 emissions limits required in AB 32 and to establish our 2020 emissions target are different from the methods used to compute emission for 2008 and beyond. This is not a problem. Moving forward it is important that we use the most current data and best available methods to estimate GHG emissions and track reductions. From a regulatory and compliance standpoint this must be done at an individual facility level to effectively reduce GHG emissions. Because the 2020 target is an overall statewide target, and equal GHG reduction requirements will not necessarily be applied to each sector, the fact that there may be inconsistencies between historical and current methodologies estimates is irrelevant on a facility basis.

G-10. Inconsistency Between GHG Inventory and GHG Reporting Protocols
Comment: The GHG inventory going forward should be consistent with the reporting protocol, so that there is a single estimate of California's GHG emissions. Further, since California's goal for GHG reduction is in terms of retuning to 1990 GHG emissions levels, the 1990 GHG inventory should be

determined using similar assumptions as underlie the reporting protocol. [Sempra(11)]

Agency Response: ARB does not agree. ARB has adopted a GHG emission reduction target based on the best available information for 1990. Establishment of an aggregate 2020 statewide emissions limit based on the 1990 level does not confer an obligation on any particular facility or sector to meet its own 1990 emissions level, or to calculate emissions on the same basis. Mandatory reporting will contribute accurate information at the facility level that enables tracking relative to specific compliance obligations, in addition to providing bottom-up data to support inventory improvements. While future regulations will need to use consistent methods to set baselines and estimate emissions for regulated entities, that consistency does not necessarily extend to setting broad targets based on top-down inventories.

G-11. Costs to Public Agencies are Underestimated

Comment: The public notice and Initial Statement of Reasons (ISOR) for the regulation do not fully reflect the costs that will be incurred by the public agencies required to report. Costs have been underestimated and the ISOR should be modified to reflect this. [NCPA(BH2)]

Agency Response: We concur that some large or complicated public facilities and entities could have relatively large costs to comply with the reporting regulation, particularly in the initial reporting years. We disagree with the conclusion that overall public costs are certainly underestimated. Public agencies include a range of facilities including certain landfills and sewage treatment plants and publicly owned electricity providers. For some of these public facilities reporting costs will be minor, in the range of $2,000 to $10,000 per year. For others, such as energy providers, we have estimated that annual costs could be in the range of $20,000 to $80,000. This is within the cost range mentioned within the comment. The variability shown is due to uncertainties in the specific costs to facilities, the number of facilities that have existing emissions systems that can be easily modified to report GHG emissions, the exact costs of verification, and other factors specific to individual facilities and general to the entire reporting program. ARB does not have reason or evidence to believe that many public agencies will incur the level of cost mentioned in the comment letter, and we believe the fiscal impact discussion in the Staff Report is accurate.

G-12. Provide Additional GHG Data Access and Transparency

Comment: The reporting and verification provisions of the proposed regulation are contrary to the principles of Environmental Justice. Commenter mentions that the public can have no confidence in either the overall inventory nor in individual company reports and these regulations result in losing the trust of the public that emissions are accurately measured and calculated using good engineering principles. The regulation cuts out public review of emissions inventory accuracy and relies on a third party consultant to the polluter who will verify the emission calculations and measurements behind closed doors. Commenter proposes that all the basis of the GHG emissions calculations, evaluations, and measurements be included in the emissions report provided to ARB…Housing data calculations at each separate company would undermine any GHG reduction system that is set up – be it a cap and trade program or some other means of controlling GHGs. [CBE(21,T6), CBE2(T8)]

Agency Response: ARB does not agree with the commenter's characterization of the reporting and verification process. ARB will make publicly available all reported emissions data as provided in section 95106(a). Other information received or generated by ARB will also be available to the public, except to the extent ARB determines that it is trade secret or otherwise exempt from disclosure under the Public Records Act. See title 17, California Code of Regulations, sections 21000-21022 for the process used to make such determinations. The regulation in no way modifies or changes the emissions data disclosure procedures that are currently in-place at ARB nor does it change the rules about what constitutes a public record.

The verification process is designed to be transparent and to ensure the accuracy of emissions data that are submitted to ARB. Verifiers will have access to all information required to prepare the GHG report. ARB will also have access to the complete facility information and the final verification report as part of its oversight process of both the reporting and verification programs.

Verification of GHG emission reports as outlined in the regulation is a central and critical part of an accurate and transparent GHG reporting methodology. The third party verification provisions of this regulation were patterned after existing procedures of respected organizations such the World Resources Institute, the California Climate Action Registry (CCAR), and the European Union Emissions Trading Scheme. The regulation's conflict of interest provisions are also consistent with or tougher than established national and international GHG reporting programs. ARB is confident these provisions will help ensure that third party verifiers are unbiased and impartial in their review of GHG emissions data reports. Staff also plans to conduct evaluations of the verification process and conduct independent audits of selected emissions reports and verifier performance each year as a further check on data accuracy and reliability.

Reporting methods incorporated in this regulation are also based on accepted methodologies developed and used by agencies such as the US EPA, IPCC, CAPCOA and API, in addition to CCAR. These methods were presented and discussed in numerous public workshops where stakeholder input from diverse groups (industry representatives, environmental and non-profit groups, and AQMD/ APCD professionals) was solicited and incorporated where appropriate. Thus, the regulation GHG reporting methods were developed in a transparent and open manner which provided all interested parties with ample opportunity to voice their concerns.

The regulation (in section 95104 and also in sector-specific sections) clearly delineates the emissions data that must be included in GHG emissions reports submitted to ARB. Additionally, section 95105 (Document Retention and Record Keeping Requirements) sets forth requirements for the retention of all records, raw and aggregated data, CEMS data, and documentation of changes, for a period of at least five years by facility operators. This provision, far from undermining the GHG reduction program, will provide ARB and verifiers additional access to all underlying data when they need it to check and corroborate all aspects of a facilities emission report.

Finally, we note that the commenter recommends that all data that forms the basis of emissions calculations, evaluations, and measurements be included in reports to ARB. This would be impractical because of the voluminous quantity of data that would be involved for many facilities. ARB believes the regulation provides the information that both the verifiers and ARB will need for their respective roles, and provides the public with detailed information that will provide transparency for the program.

G-13. <u>Data Not Reported Not Available to Public</u>

<u>Comment</u>: The Confidentiality section of the regulation specifically states "Data used to calculate GHG emissions that are not part of the annual emissions data report shall not be required to be made public…." (Section 95106(c)) This is not only a terrible idea, it is entirely unnecessary for the protection of legitimate trade secret information, since there are existing trade secret protections for companies that have been routinely applied by ARB. This new provision goes beyond existing protections, cutting out the public completely, and must be struck. [CBE(21)]

<u>Agency Response</u>: The referenced language was included in a pre-release version of the regulation. It was deleted from the regulation and was not included in the proposed regulation released October 19th, 2007, or subsequent revisions.

G-14. <u>Minimal Public Outreach and More Access Should Be Provided to Data</u>

<u>Comment</u>: There has been very little public outreach in the Mandatory Reporting process. This process had very minimal involvement from the environmental community. Despite CBE's decades of detailed work on oil refinery air pollution, we were not contacted for involvement in development of the refinery reporting regulations at any time. We only became aware of this process in late spring or early summer of this year on our own. While we understand that ARB has been under a strict legislative deadline to finalize regulations, the process has required non-profits like CBE and other Environmental Justice organizations to jump at very short notice, without funding, into this process. The Environmental Justice committee work on Early Action items has been the only process where ARB has directly involved the EJ community. Because of this, it is particularly disturbing

that ARB has taken the approach of allowing secret evaluations behind company doors of emissions reporting, where the public cannot access it, rather than requiring that this be submitted to ARB where the public will be able to add its scrutiny. Public scrutiny of data and the basis of data has always been a crucial part of quality assurance. [CBE(21)]

Agency Response: ARB undertook extensive outreach efforts in the development of the Mandatory Reporting Regulation. In December 2006, staff held the first of five workshops to present initial ideas for mandatory reporting. All workshops were widely noticed through email listserve notices, the ARB website, personal contacts, and in some cases via letter. In addition, industry sector teams met fourteen times in public meetings throughout the spring and summer to discuss sector-specific concerns. The commenter participated in several of these meetings. Staff also met regularly with individual stakeholders upon request to hear their concerns and recommendations. Environmental organizations participated in workshops and sector meetings, and met individually with staff to share their concerns and recommendations. Staff was available on a continuing basis to discuss any stakeholder concern. In addition, the formal rulemaking process provided further opportunities to comment on the regulation and shape its content. See response to comment G-12 regarding the release of data.

G-15. Program Oversight Advisory Board

Comment: Suggest creating a private sector advisory board to conduct annual independent review of reporting and verification activities to ensure program cost effectiveness and minimum burden on regulated community. [CLFP(10)]

Agency Response: The ARB develops and implements its regulations in an open public process. We commit to ongoing consistent engagement with the regulated stakeholders and other interested parties. In addition, we have committed to bringing updates of the GHG reporting regulation to the Board to meet future needs and refine the reporting requirements as needed. Based on the existing high level of public participation and the ease of access to ARB staff and management, at this time we believe that the creation of an ongoing "private sector advisory board" is unnecessary. We will continue having workgroup meetings, public and industry-sector workshops, one-on-one meetings, and other outreach to ensure that we are responsive to any stakeholder difficulties or concerns in implementing the reporting regulation.

G-16. Reported Emissions Should Receive Appropriate Consideration

Comment: Has the ARB considered defining "appropriate consideration" as it applies to the data submitted under this regulation receiving "appropriate consideration" of these emissions under any future international, federal, or state regulatory scheme related to GHG emissions? [Raytheon(29)]

Agency Response: It is not possible or appropriate for the ARB to define how other regulatory schemes treat the data submitted under the California mandatory program. However, in developing the regulation, we strived to develop a transparent, rigorous, and consistent reporting program. We anticipate that due to the well specified reporting requirements and stringent verification requirements, submitted data will be acceptable to a variety of other GHG reporting programs under development.

G-17. Implement Carbon Tax

Comment: Will California consider implementing a carbon tax? If not, why not? This has all the benefits of reporting greenhouse emissions (the amount of greenhouse gases is directly reflected in the price), provides financial incentives for both innovation and good consumer choices, and avoids the bureaucracy that would be required for reporting emissions. [TSuen(14)]

Agency Response: Among other provisions, the Global Warming Solutions Act of 2006 (AB 32) required that the ARB develop a mandatory GHG emissions reporting program. A carbon tax option has been explored in discussions relative to the Scoping Plan development and if the Board decides to investigate this mechanism, it will do so in a future process separate from this regulation.

We disagree with the statement that a carbon tax has all the benefits of reporting greenhouse gas emissions. Regardless of the mechanisms developed to reduce GHG emissions, the reporting of GHG emissions by individual facilities is necessary to effectively track current and future GHG emissions from the emission sources. A carbon tax on its own would not allow us to effectively determine facility emissions, nor provide rigorous and consistent methods for calculating and verifying those emissions.

G-18. Insert Language to Address CEQA Issues

Comment: Include provisions within the regulatory package to provide some certainty related to GHG thresholds and mitigation raised by recent California Environmental Quality Act (CEQA) lawsuits are threatening the comprehensive approach to GHG reductions envisioned by AB 32 and are turning GHG reductions into case-by-case, project-by-project negotiations. Include provisions within the regulation that state the facilities not required to report under this regulation are considered “de minimis” for purposes of CEQA. Also state that projects under the 25,000 metric tonne reporting threshold shall be considered to have less than a significant impact. [AB32IG(47)] Add language in the regulation to address potential CEQA requirements. The commenter provided extensive regulatory text dealing regarding CEQA and GHG emissions. This Article is entitled *CEQA Significance and Mitigation of Greenhouse Gas Emissions* and would preclude case-by-case or project-specific GHG mitigation requirements being imposed on any facility subject to Article 1 of the present mandatory GHG reporting regulation. [WSPA(23)] Include CEQA guidance for those who are going to have to be permitting. [Chev(T2)] CEQA needs to be addressed in a way that looks holistically at refineries. [CBE(T6)] Provide CEQA linkage in reporting regulation; it is important that CEQA be first and foremost in our minds as we move forward. [WSPA(T23)]

Agency Response: The mandatory reporting regulation is not the appropriate venue for addressing the CEQA issues raised by AB 32. The Governor's Office of Planning and Research is developing CEQA Guideline updates, and in the context of its June 19, 2008 Technical Advisory, has asked ARB technical staff to recommend a method for setting CEQA thresholds that will encourage consistency and uniformity in the CEQA analysis of GHG emissions throughout the state. Current information is posted on the OPR website at this address: http://opr.ca.gov/index.php?a=ceqa/index.html. Finally, we note that the emissions thresholds for mandatory reporting requirements were designed to comply with AB 32's direction that ARB focus its efforts on the sources that contribute the most GHG emissions, and were not established as thresholds of significance for GHG impacts under CEQA.

G-19. Develop a List of Feasible Mitigation Measures Appropriate for GHG Projects
Comment: Encourage the board to have the Executive Office develop a list of feasible mitigation measures that would be appropriate for mitigation projects where GHG emissions are deemed to be significant. [AB32IG(47)]

Agency Response: This comment is not relevant to the current rulemaking, which requires GHG emission reporting and includes no requirements for emissions reductions. See response to G-18.

15 DAY COMMENTS – FIRST RELEASE AND STAFF RESPONSES

Because of the relatively small number of comments received during the 15-day comment periods, comments are not subdivided into individual regulation sections as was done for the 45-day comments. However, the comments and responses are generally ordered to reflect the sequence of the regulation.

H-1. Do Not Require Reporting for Electric Facilities < 2,000 tonnes
Comment: Electricity generating facilities that are subject to reporting, and then drop below 2,000 tonnes CO_2/year for three years can cease reporting. Do not require reporting for electricity generating facilities that have produced less than 2,000 tones CO_2/year for the three years prior the GHG reporting rule effectiveness. [BVES(FF10)]

Agency Response: Electricity generating facilities that emit less than 2,500 tonnes CO_2/year from electricity generating and have a nameplate of less than 1 megawatt are not subject to reporting. The 2,000 tonne threshold in section 95103(e) only applies to the opting-out of facilities that were previously emitting

≥ 2,500 tonnes CO_2/year and reduced their emissions. The lower, 2,000 tonne value (versus < 2,500 tonnes) is used for the opt-out threshold to avoid having small variations in emissions affect applicability of the regulation.

H-2. Size: 25,000 vs 2,500 metric tones
Comment: Change all references to the 2,500 reporting threshold to 25,000 metric tones. [Hagen(FF2)]

Agency Response: The specific 2,500 metric ton threshold applies to electricity generation facilities and cogeneration facilities and is necessary to meet statutory requirements to account for all GHG emissions from electricity generation. ARB therefore rejects this recommendation.

H-3. The definition of "accuracy" needs clarification
Comment: The current definition of accuracy is difficult to understand (section 95102(a)(1)). Since this definition interacts significantly with the fuel measurement accuracy requirements in section 95103(a)(9), the definition needs to be reworded and clarified to avoid confusion and potential future compliance issues. [WSPA(FF17)]

Agency Response: The definition of accuracy was drawn from internationally accepted GHG reporting guidelines (IPCC 2006 Guidelines for National Greenhouse Gas Inventories). Reporters need to insure that instrumentation is designed to meet the accuracy requirements in Section 95103(a)(9) and is maintained and calibrated in a manner specified by the manufacturer. Specific edits were not suggested by the commenter. ARB believes the definition is clear as drafted and will support this need for accurate instrumentation.

H-4. Definition of a Hydrogen Plant
Comment: As currently worded the regulation is sufficiently broad as to include reforming units in the definition of hydrogen plants. Suggest adding the qualifying phrase "as a primary product" in order to clarify that only dedicated hydrogen plants are covered by hydrogen plant reporting requirements. [WSPA(FF17)]

Agency Response: Secondary hydrogen producing units are not included in the GHG reporting requirements for hydrogen plants. The various refining processes that produce hydrogen as a bi-product do not involve steam methane reforming or the partial oxidation of hydrocarbons. The definition of hydrogen plant excludes these ancillary processes.

H-5. Modify Definition of Operator and Clarify Reporting as the Operator of an Electric Generating Facility
Comment: Certain sections and definitions in the Modified Regulation require revision in order to clarify the responsibility of retail providers and marketers for various aspects of reporting. Recommend adding language to sections

95111(c), 95111(d), and 95111(f) to clarify that these sections apply only to the extent that the retail provider or marketer operates the facility. [SCE(FF8)]

Agency Response: ARB revised the regulation; however, rather than adding language, ARB chose to delete “retail providers and marketers” from sections 95111(c) and 95111(d). With the reference to retail providers and marketers deleted, the only remaining reference is to the operator of a generating facility. ARB did not change 95111(f) because in this section applicability is not linked to operational control but rather to operators, retail providers, and marketers who have “responsibility for maintaining in proper working order.” This stipulation is stated in section 95111(a)(1)(J). Thus, limiting the requirement to operational control would be incorrect and conflict with the express terms of the regulation.

H-6. Definition of a Storage Tank
Comment: Given the current definition of storage tank, there is the concern that any size container might be subject to reporting. [WSPA(FF17)]

Agency Response: The GHG reporting regulation at section 95113(c)(3)(A) provides a specific method and software tool for estimating the GHG emissions from storage tanks. Because the tool used to calculate storage tank emissions will not accept data for small containers, this should not be a concern.

H-7. Clarification of the Storage Tanks Covered by the Regulation
Comment: Request that the term “gas oil” be defined to add clarity to the range of tanks covered by the methodology. [WSPA(FF17)]

Agency Response: ARB does not believe this definition is necessary. Gas oil is a term used frequently in the AQMD Permitting Process. For example, the ConocoPhillips Final – Major Facility Review Permit issued by the BAAQMD (12/1/03) lists Tank 155 at the facility as a storage tank for gas oil.

H-8. Exclude Ethane From VOC Definition
Comment: The definition of VOC should exclude ethane to be consistent with the VOC definition used by APCDs and AQMDs. [Covanta(FF1)]

Agency Response: The regulation’s definition for VOC does not include a complete list of all excluded compounds, but defines a VOC as a compound that “participates in atmospheric photochemical reactions.” Ethane does not fall under the definition because it is considered to have negligible reactivity.

H-9. Add Feedstock Reporting Requirements Specific to Hydrogen Plants Section 95103(a)
Comment: Requests the addition of a stipulation to the General Reporting Requirements (Section 95103(a)) that the Fuel Analytical Data Capture and Fuel Use Measurement Accuracy requirements in sections 95103(a)(8) and (9) respectively, be modified to include feedstock as well as fuel. [Praxair(FF5)]

Agency Response: ARB appreciates the comment but does not feel that this addition is necessary. The more general requirement for "reasonable assurance that the reported facility emissions are within 95 percent of the actual total emissions for the facility" will ensure high quality and accurate emissions data.

H-10. Do Not Require Device Level Reporting

Comment: Do not require reporting at the device level (e.g., by permit number). Process level data is sufficient and device level reporting would not add value to the GHG inventory while adding to workload and possible errors. Suggest allowing device reporting, but not requiring it as long as process level data are provided. The disadvantages of device reporting outweigh the advantages. [ECOTEK(FF16)]

Agency Response: ARB disagrees and believes device-level or process unit-level reporting as required in section 95103(a)(2) will provide substantial advantages without adding substantially to costs. The regulation requires monitoring and reporting of fuel consumption for each process unit or group of units only where fuel use is separately measured for the unit or units. The regulation does not require the installation of new equipment to meet this requirement. The inclusion of process unit data, when available, provides valuable additional information about the individual types of equipment and sources producing GHG emissions. This collected data will assist with future regulatory efforts and in the tracking of changes of GHG emissions. Because reporting of process unit data is similar to the existing requirements for criteria and toxics pollutant emissions reporting, it should not pose a resource burden or technological challenge for the reporting facilities.

H-11. Performance Criteria and Verification for Fuel Flow

Comment: Request that fuel meters that are not used in calculating the emissions required under this section, shall not be subject to requirements in other section of this regulation. Request the regulation be amended to specify that only fuel activity data "used to calculated GHG emissions" be subject to ±5% accuracy requirement. [WSPA(FF17)]

Agency Response: ARB concurs that the accuracy of fuel activity data is important where it affects emissions calculation, and does not intend the accuracy requirement to apply at meters that do not affect such calculations. Section 95103(a)(9) of the regulation has been amended in response to this comment.

H-12. Time Remaining for Implementation of Reporting Regulations

Comment: Concerned about the shrinking time remaining to successfully execute the remaining critical elements necessary to support the successful implementation and compliance with the regulation. These items include compliance guidelines, development of the verification training program, the actual training of enough qualified verifiers to support the reporting program, etc. [WSPA(FF17)] Concern that belated publication of this rule has created a need for additional time for the design, purchasing, and installation of some of the required monitoring equipment, and recommend that all or portions of the CCAR inventories should be acceptable as temporary substitutes as needed during the interim period. [Valero(FF6)]

Agency Response: ARB is actively working to provide the additional elements needed to support implementation of reporting and verification. In addition, reporters are allowed to use "best available data and methods" to estimate the 2008 emissions reported in 2009. For all regulation specified GHG sources that already report data to CCAR, these data will be considered sufficient in 2009 emissions reports. Where the regulation requires data on sources not specifically identified in CCAR protocols, however, reporters must use other data and methods to arrive at a best available estimate of emissions. We also realize that initially, significant lead time may be required to purchase and install instrumentation. ARB will work with operators to find workable solutions consistent with the regulation in those special cases.

H-13. Requiring Synchronized Verification Will Create Erratic Workloads

Comment: The mandated prescription requiring all operators to obtain verification during the same period with gaps of two years in between will result in an onerous boom/bust work and profit cycle for verification operators. Suggest requiring verification of 1/3 of locations annually and allowing operators to select the year of verification would streamline and harmonize reporting. [Hagen(FF2)]

Agency Response: We understand the desire for a steady verification workload, both to sustain the verification program and to help assure adequate review of each report subject to verification. This was a consideration in our proposals for six-month verification periods and staggered verification deadlines within each report year.

The majority of facilities that will have to report their GHG emissions are required to obtain annual verification services. These facilities may choose to obtain two years of less intensive verification services following a year of full verification services. Although this will result in generally more intensive verification years in the beginning of the program, we expect the balance of work to even out over time. Verification cycles will increasingly vary over time due to variety of factors including: changes in verification body utilized, phase in of new facilities, the desire to obtain a positive verification opinion following an adverse opinion, and changes in facility operations. Verifiers of emissions data reports will also be able to market their skills as project verifiers, and as consultants for facilities developing inventories and emissions data reports (when they are not carrying out verification services for the same operator), among their other work.

H-14. Application of Emissions Limits to Hydrogen Plants Which Are Part of a Refinery

Comment: Suggest that clarification concerning cessation of reporting criteria is necessary in the case where a hydrogen plant is imbedded in a refinery. [WSPA(FF17)]

Agency Response: The regulation applies a separate reporting requirement to hydrogen plants; thus the cessation of reporting provisions apply to the hydrogen plant and the refinery as discrete facilities. When emissions from a hydrogen plant drop below 20,000 MT CO_2 for three successive years, a discrete emissions data report is no longer required. An imbedded plant under the operational control of the refinery remains a stationary source within the refinery, however, so its emissions must still be reported by the refinery.

H-15. Exclude Biomass Use Reporting

Comment: Recommend deleting all reporting of biomass as this reporting is onerous and heavy handed. [Hagen(FF2)]

Agency Response: ARB supports more reliance on biomass-derived fuels as substitutions for fossil fuels when net GHG reductions can be achieved. We believe it is important to track the growth in biofuels usage at facilities subject to mandatory reporting, both to monitor the success of reduction strategies and to ensure rigorous and consistent emissions accounting as required in statute. We have provided additional methods and reduced requirements for biomass facilities in an effort to make compliance easier for operators using biomass-derived fuels, but for the revisions stated above, we reject the recommendation that all reporting requirements be deleted.

H-16. Uncertainty Goals Rather Than Prescription

Comment: Recommend setting a long term uncertainty goal and then let operators select sampling frequency. [Hagen(FF2)]

Agency Response: Methodologies and sampling frequencies specified in the regulation were chosen based on available data concerning source strength and variability. The goal of reporting consistency and data accuracy would not be well served by letting operators choose sampling frequency, and ARB rejects this recommendation.

H-17. Fuel and Biomass Testing Sampling Requirements

Comment: The fuel sampling requirements are heavy handed and operators should be allowed to choose sampling and testing frequencies based on the level of overall uncertainty desired. [Hagen(FF2)]

Agency Response: The methodologies set forth in this regulation were chosen based on source strength and fuel variability parameters. Allowing operators to choose frequencies would not serve the goal of sampling consistency and could result in significantly reduced data quality. ARB therefore rejects this recommendation.

H-18. Confidential Information Protection

Comment: ARB (or CARB) must ensure that the regulation adequately protects confidential and commercially sensitive information. It may be possible to impute transaction information based on resource-specific or default emission factors if reporting entities are required to report such imputed emissions for all transactions. Reporting entities should have the ability to submit any information to CARB on a confidential basis if such information is likely to reveal commercially sensitive information (e.g., how much power was imported/bought and from which source/counterparty). The CARB should not prejudge what confidential information may be protected as a trade secret or otherwise protected from public disclosure. Additionally, any publication by or on behalf of CARB of total emissions from retail provider must be summarized and aggregated a level sufficient to make the identification of individual transactions impossible in order to protect the retail provider's confidential and commercially sensitive information. [SCE(FF8)]

Agency Response: Please see response to comment B-56. Although reporters will be able to identify information that is not emissions data as confidential, ARB is required by law to make a determination as to status of the information if its release is sought or proposed.

H-19. CEMS and Unintended Reporting Obligations

Comment: Concern that the requirement for reporters who install and operated CEMS to operate pursuant to requirements in 40 CFR may trigger an unintended reporting obligation (to US EPA). [WSPA(FF17)]

Agency Response: The regulation does not place facility operators under any obligation to report to U.S. EPA, but simply to operate and maintain CEMS instrumentation as specified. We do not believe modification is necessary.

H-20. Potential Over-Specification of Sampling Time Interval

Comment: In including a requirement to sample 3 times per day (every eight hours) the regulation implies that samples have to be taken exactly 8 hours apart. Request that additional language be added to specify that "sampling programs should be designed to reflect the daily average carbon content of the system." [WSPA(FF17)]

Agency Response: ARB believes the regulation allows some approximation of sampling frequency as long as the operator obtains fuel samples and chooses measurement locations in a manner that minimizes bias and is representative of each fuel gas system (per section 95125(e)(2) for the same fuel). Sampling three times daily with reasonable variation in time interval is adequate as long as the samples and locations are representative and unbiased. We do not find a change to the regulation necessary.

H-21. Air Districts Already Have N_2O Limits, So Use Their Source Test Data

Comment: Districts already have N_2O limits. In the SJV district the NO_x limit is set at 9 ppm and existing source testing data for NO_x should be acceptable for meeting the GHG reporting requirements. The default N_2O emission factor used for GHG emission reporting should be set to the district limit. Source testing is expensive for facilities, so approved district source test data should be used for reporting N_2O emissions and annual source testing should not be required for N_2O. [Silva(FF4)]

Agency Response: On the first point of this comment, there appears to be some confusion regarding the regulation. The GHG regulation does not require reporting of NO_x emissions. Also, air districts do not have N_2O emission limits, which is a GHG. Instead, they have NO_x emissions limits, which is a criteria pollutant. Therefore, air districts (and most facilities) do not have existing N_2O source test data available which could be used to meet the GHG regulation requirements. For facilities which do have N_2O source testing in place, the regulation allows for approval of the source test protocol by ARB and use of the collected data. Note that source testing for N_2O is optional, and default emissions values are provided for those who do not want to perform facility source testing. For those who choose the N_2O source test option instead of using default factors, annual source testing is necessary to adequately track variability in facility processes and emissions over time.

H-22. Annual Source Testing for N_2O

Comment: Objection to the requirement of annual source testing for N_2O emissions should the reporter choose to do source testing rather than use default emissions factors. The commenter also points to the SJVAPCD NO_x limit rules and suggests that the GHG reporting requirements duplicate Air District rules. [Silva(FF4)]

Agency Response: There appears to be confusion regarding the two different species - the criteria pollutant NO_x (NO and NO_2) and the greenhouse gas N_2O. Source testing mandated by the local air districts to insure compliance with NO_x emissions standards is not applicable to calculations of the greenhouse gas emissions of nitrous oxide (N_2O). See response to comment H-21.

H-23. Supervision of Site Testing

Comment: Concerns over the language that indicates that testing (at geothermal facilities) needs to be conducted under the supervision of agency staff. This can be interpreted differently and may imply that direct supervision is necessary for the testing. In addition, the testing conducted that yields the source specific CO_2 emissions factors is conducted in conjunction with testing required by the local agencies for H_2S monitoring. Since the local air districts are already regulating and monitoring this testing, they would be best suited to approve the CO_2 testing as well. [Calpine(FF14)]

Agency Response: Please see response to comment C-37. ARB does not interpret the language "under the supervision of ARB or the air pollution control district" to require direct supervision of the test by ARB staff, and we do not anticipate a duplication of effort once a site test plan has been approved.

H-24. Revise Regulation After Point of Regulation Determined for Electricity Sector
Comment: In order to be responsive to the California Public Utilities Commission (CPUC) and California Energy Commission (CEC) joint recommendations for the electricity sector, the regulation includes certain duplicative reporting. SCE requests that ARB revise the regulation to eliminate duplicative reporting when the point of regulation has been determined. [SCE(FF8)]

Agency Response: ARB agrees. See response to comment A-15.

H-25. Future Revisions to Emissions Attribution and to Reporting Requirements
Comment: ARB should revise the emission attribution methods during a formal rulemaking process. In addition, the mandatory reporting regulation will need to be revised to remove unnecessary reporting requirements once the point of regulation for the electricity sector is decided. [LADWP2(FF11)]

Agency Response: ARB agrees. ARB will consider both the emissions attribution methodology and reporting requirements in a public process when future regulatory design has been determined. Also see response to comment A-15.

H-26. Clarify that Region of Destination is Determined by the Point of Delivery
Comment: The term 'region of destination' is ambiguous because it may refer to the point of delivery or the ultimate destination for the power. Since the seller of wholesale power may not know where the power will ultimately be consumed, we suggest that this term either be replaced by 'point of delivery', or clarify that 'region of destination' is based on 'point of delivery'. [LADWP2(FF11)]

Agency Response: ARB agrees that region of destination is determined by the point of delivery. ARB revised section 95111(b)(3)(J) to make this clear.

H-27. Determine Emissions from Megawatts Hours Taken Not Ownership Share
Comment: The regulation requires that retail providers report percent ownership share and facility net generation (MWh) for fully or partially owned generating facilities. We suggest adding that retail providers should also report MWh received from these facilities if they have not already reported it as an electricity transaction rather than estimating what they received by multiplying their percent ownership share by facility net generation. Concerned that percent ownership share may be used to assign responsibility for emissions. [LADWP2(FF11)]

Agency Response: Electric power taken from a partially owned generating facility should be reported as power "purchased or taken" from a specified source. Ownership share information is in addition to reporting power purchased or taken. Since this regulation addresses reporting only, there has been no assignment of emissions responsibility. That will be determined during the development of future emission reduction regulations. Determining how or whether ARB will use ownership share information will be part of that public process.

H-28. <u>Revise Methodology to Distribute Emissions for Bottoming Cycle Cogeneration Facilities</u>
<u>Comment</u>: Request that bottoming cycle co-generation facilities distribute emissions associated with supplemental firing only and not be required to include additional emissions associated with the manufacturing process. States that that fuel use in, and emissions from, the high-temperature manufacturing process are separate from, and bear no relation to, electricity and low-temperature thermal energy production. Stated that the methodology in the regulation was inconsistent with the Federal Energy Regulatory Commission (FERC) approach for calculating efficiency of bottoming-cycle cogeneration facilities. Stated that the revisions to the methodology that they were recommending were consistent with the approach taken by the United Nations in evaluating reductions in emissions of greenhouse gases from cement kilns. [Geomatrix(FF7)]

<u>Agency Response</u>: See response to comment C-75. Also, the ARB regulation is designed to provide for facility-level emissions calculations sufficient to support a monetization of carbon-equivalent emissions. This fundamentally different purpose often requires quantification methods that vary significantly from methods developed by other organizations for other purposes, such as the Federal Energy Regulatory Commission (FERC) for qualifying cogeneration facilities or by the United Nations Clean Development Mechanism for a baseline methodology for GHG reductions from cement plants. It is especially important to obtain information on emissions from application of this technology where it helps meet electrical load. This provision is consistent with the Act's requirement to account for emissions from all consumed electricity.

H-29. <u>Efficiency Factors to Distribute Emissions for Cogeneration Facilities</u>
<u>Comment</u>: Support for triennial verification and abbreviated reporting option for small cogeneration facilities. Requests operator flexibility in choosing the facility-specific efficiency factors for distribution of emissions between useful energy outputs. [EPUC/CAC(FF12)]

<u>Agency Response</u>: No change is needed at this time. To ensure reporting consistency, the proposed regulation requires operators to use and report the efficiencies, if known; otherwise, the provided default values must be used. As requested, the regulation provides for triennial verification for cogeneration facilities under 10 megawatts, and abbreviated reporting for self-cogeneration cogen facilities under 10 megawatts who are not otherwise subject to reporting. See also responses to comments C-71 and C-74.

H-30. An Emission Methodology for Coke Calciners is required

Comment: There currently is not a calculation method appropriate for the coke calcination process. WSPA proposes using a modified International Aluminum Industry HG Protocol for calculating these emissions. [WSPA(FF17)]

Agency Response: ARB appreciates the commenter pointing out the need for an additional methodology to address what we understand is a significant source at two refineries. Although we are not prepared to require exclusive use of a new methodology now, we will include in the reporting tool the option for any facility to specify additional sources and report emissions for those sources. The methods used to estimate these emissions would be subject to review by the verification team but not prescribed by ARB. ARB will consider developing a method for this source for inclusion in a future revision to the regulation.

H-31. Fuel and Feedstock Consumption Reporting Requirements

Comment: Request addition of language that will clarify the intention for reporting of feedstock consumption to specify feedstock consumption used to calculate GHG emissions. [WSPA(FF17)]

Agency Response: ARB agrees that the intent of the regulation is not to require reporting of all feedstock consumption (e.g. feedstock to a polypropylene plant), but only feedstock consumption that results in GHG emissions (e.g. natural gas to a hydrogen plant). Based on this comment, section 95113(a)(3) of the regulation was updated to make this distinction.

H-32. Flexibility in the Determination of SRU Gas Composition

Comment: Request for flexibility concerning the continued annual use of an approved source test plan. As the regulation is currently structured, if a reporter chooses the option of determining a molecular fraction of CO_2 using an ARB approved source testing plan, they are required to repeat this test every succeeding year and do not have the option of using the default value provided by ARB. There are potential safety issues involved in source test sampling, which could be avoided if annual sampling is not required. [WSPA(FF17)]

Agency Response: Particularly during the initial years of the GHG reporting program, it is important to measure and collect annual GHG source test data where this option is selected. We will use this information to assess the completeness, accuracy, and consistency of reported data. Where source sampling risks appear unacceptable, facility operators do not have to select the source test option to begin with. For those choosing to test, ARB will work with operators to develop approvable source test plans which minimize potential safety issues. ARB also has the option of rescinding the approval of source test plans where the safety risks of continued testing outweigh the benefits. For these reasons we believe that no changes to the regulation are required at this time.

H-33. <u>The Use of Data Derived from AQMD Mandated Sampling</u>

<u>Comment</u>: WSPA suggests that in lieu of using a default conversion factor (carbon content of NMHC), when reporters are required by AQMD rules to determine this value by sampling and measurements, that they use this value. [WSPA(FF17)]

<u>Agency Response</u>: ARB agrees that use of values obtained from sampling will result in improved emissions data quality where available, and appreciates the comment. The regulatory text has been revised accordingly.

H-34. <u>Omission of Equation Definition</u>

<u>Comment</u>: The conversion factor 3.664 is not defined in section 95113(d)(2)(A) and section 95113(e)(3). Additionally section 95125(f)(1)(C) refers to section 95125(d)(3)(A)(1). There is no section (A)(1) only a section (A). [WSPA(FF17)]

<u>Agency Response</u>: ARB appreciates the comment and has made these corrections.

H-35. <u>Equation Variable Subscripts Require Correction</u>

<u>Comment</u>: The definition and subscript denotation for the instantaneous heating value (Section 95125(e)(3)) should be revised to avoid confusion. [WSPA(FF17)]

<u>Agency Response</u>: ARB appreciates the comment and has made these corrections. The HHV variables in the equations in sections 95125(e)(3) and 95125(e)(4) have been modified (specific subscripts added to each) to distinguish and differentiate the two variables.

H-36. <u>Double Counting of Stationary Combustion Emissions of CH_4</u>

<u>Comment</u>: Praxair suggests that the carbon contained in methane emissions from flaring and stationary combustion will be double counted – once in these sections and again in 95114(b)(2). [Praxair(FF5)]

<u>Agency Response</u>: Established international and federal GHG calculation methodologies do not correct mass balance CO_2 emissions for the very small fraction of carbon emitted as un-combusted CH_4. We do not believe that the "double-counting" concern will significantly affect reported emissions and do not find that a change to the regulation is necessary.

H-37. <u>Steam Based Method for Waste-Derived Fuels Combusted at Cement Plants</u>

<u>Comment</u>: Request that section 95110 be revised to allow operators of cement plants to use the methodology in section 95125(h)(1) when combusting biomass solids and waste-derived fuels. [Geomatrix(FF7)]

<u>Agency Response</u>: No change is needed. Per a discussion with the commenter, ARB staff concluded that cement plants do not have boilers and therefore, cannot use the method described in section 95125(h)(1).

H-38. Confusing Language in Section 95125(h)(2) Regarding Exemption

Comment: Language is confusing in section 95125(h)(2) relating to an exemption for waste-derived fuels with 30 percent biomass and suggested revised language. [Beta(FF3)]

Agency Response: ARB agrees that the sentence as written was unclear. ARB revised the language to read "waste-derived fuels that are less than 30 percent by weight of total fuels combusted…" The clarification enables the operator to know whether they qualify for the exemption because the exemption is based on known information, namely the weight of waste-derived fuels compared to total fuels combusted. We note that the implication of using the exemption is that waste-derived fuels will be considered 100 percent fossil fuels unless the biomass portion is measured according to the methodology in 95125(h)(2).

H-39. Addition of Waste-Derived Fuels to Section 95125(h)(1)

Comment: Request that the title to section 95125(h) include waste-derived fuels and that waste-derived fuels be added to the methodology in section 95125(h)(1). [Geomatrix(FF7)]

Agency Response: The regulation was revised to include "or Waste-Derived Fuels with Biomass" in the title of section 95125(h). Per a discussion with the commenter, ARB staff and commenter staff agreed that no change was needed in section 95125(h)(1) to accommodate cement plants because the methodology is designed for boilers and boilers are not used at cement plants.

H-40. Option to Use Alternative Test Methods

Comment: The methodologies provided in section 95125 are complex and appear to be limiting in terms of test methods. Noted that it was not clear that current provisions would apply to all cases in the future and recommended that the regulation include the option to use additional equivalent methods approved by the ARB executive officer. [Geomatrix(FF7)]

Agency Response: ARB rejects this recommendation for the following reasons. The regulation must specify the test methods to be used and provide public access to instructions for these methods. The use of prescribed methods also insures consistency in implementing the regulation. ARB is open to evaluating specific methods proposed by stakeholders with the possibility of including them in future revisions to the regulation as appropriate.

H-41. N_2O and CH_4 Methodologies for Off-Road Mobile Combustion Sources

Comment: The definition of mobile combustion sources includes both on-road and off-road motor vehicles; however, the methodology to calculate N_2O and CH_4 emissions is not workable for off-road vehicles because the method is based on mileage. ARB should clarify if the intention is for operators to report only CO_2 emissions from mobile sources. If not, then an emissions methodology for N_2O

and CH_4 should be established in section 95125(i)(3) and Appendix A that is workable for off-road vehicles. [SCE(FF8)]

Agency Response: The regulation permits choice among the gases voluntarily reported for mobile sources, both on-road and off-road. We agree that the methodology provided in the regulation for calculating N_2O, and CH_4 from mobile combustion sources is not appropriate for off-road motor vehicles. Operators may voluntarily report off-road N_2O and CH_4 using appropriate methods of their choosing, subject to review in the verification process. We do not believe amendment to the regulation is required since reporting for these sources is voluntary.

H-42. Modifications are Required to Provide Emission Factors for Low Btu Gases
Comment: In two Sections (95111(a)(1)(c) and 95125(b)(1) reporters are not provided a viable reporting option for CH_4 and N_2O Stationary Combustion emissions from Low Btu Gases. Language is required to allow reporters to use 95125(c)(1)(A)(2) for Low Btu Gases. Additionally, CH_4 and N_2O emissions factors need to be added to Appendix A-9. [WSPA(FF17)]

Agency Response: The regulation was modified to address this issue. ARB has now included CH_4 and N_2O Emission Factors for Low Btu Gases (Derived Gases) in Appendix-A Table 6 and specified a sampling frequency.

H-43. CH_4 and N_2O Emissions Factors for methane, hydrogen and CO
Comment: Praxair requests that CH_4 and N_2O emission factors for methane, hydrogen and carbon monoxide be added to Appendix A-9. [Praxair(FF5)]

Agency Response: ARB understands that methane, hydrogen and carbon monoxide are rarely if ever combusted as pure fuels. Typically methane is contained in a mixture such as natural gas, and hydrogen and carbon monoxide are contained in "Derived Fuels" such as coke oven gas. We think the emissions factors found in the regulation are sufficient to allow calculation of CH_4 and N_2O emissions from these fuels.

H-44. Detailed Recommendations & Corrections
Comment: Recommend various changes to terminology, spelling and definitions. For example, change 'tonnes' to 'tons,' change 'kg' to 'Kg,' and adding '(Mg)' after 'Megagrams'. [Hagen(FF2)]

Agency Response: ARB reviewed the suggested changes and determined that the recommended changes to the regulation are not necessary. We think that the regulatory text is sufficiently clear and unambiguous in the cases identified by the commenter.

H-45. Include Short Ton to Metric Tonne Conversion

Comment: Include short ton to metric tonne conversion in Table 1, Appendix to clarify that a short ton equals 2000 pounds. [ECOTEK(FF16)]

Agency Response: The definition of "ton" is provided in the regulation definitions at section 95102(a)(191) and means a short ton equal to 2000 pounds. This change is not necessary.

H-46. Include Additional Emission Factor Units and Conversion Assistance

Comment: The public in general is not very comfortable with the metric system. Include units that match the original emission factor source document. Provide emission factors in terms of pounds/fuel unit and include English to metric conversion factors. Provide EFs in terms of metric tonnes/fuel unit. Report emissions in pounds, tons, and metric tonnes. [ECOTEK(FF16)]

Agency Response: We provide numerous units conversion factors in the regulation and any other conversion factors are readily available in the public domain, so we did not include emission factors in all major common units. Also, it is global convention to report GHG emissions in units of metric tonnes and we standardized to that convention to reduce confusion for those who may have GHG reporting requirements in other jurisdictions and so that ARB is consistent with other programs.

H-47. Require Reporting of Liquids in 1000 Gallon Units

Comment: Agree with the current requirement to report in MMScf for gases, tons for solids, and MMbtu for energy. Suggest changing units for liquids reporting from gallons to 1000 gallons to be consistent with air district reporting units which could minimize conversion and data entry errors. [ECOTEK(FF16)]

Agency Response: Reporting in units of gallons is sufficient for the GHG reporting regulation and a change to 1000 gallons is not necessary. We believe that those reporting will be able to effectively convert any existing data from 1000 gallons to gallons with minimal errors and effort. Liquid fuel reporting units of 1000 gallons could be helpful when large quantities of fuel are reported, but could be cumbersome when smaller quantities are reported.

H-48. Adjust Reported EF Units to Include MMScf

Comment: In section 95104(a)(9) update the units for emission factor reporting from Scf to MMScf to be consistent with other units used in the regulation. [ECOTEK(FF16)]

Agency Response: This edit has been made to make the units reporting requirements for emission factors consistent with the units convention used throughout the regulation.

Verification Summary of Comments and Agency Responses

H-49. The Entity Responsible for Submitting a Verification Opinion to ARB
Comment: Request that ARB change the reporting regulation to require the operator (rather than the verification body) be responsible for submitting verification opinions to ARB, consistent with current CCAR practices (Section 95103(c)(3)). [WSPA(FF17)]

Agency Response: In a mandatory reporting context, ARB believes it is important that the responsibilities of all parties be specified, and finds it appropriate that the author of the verification opinion be responsible for its timely submittal to ARB. In the absence of this requirement it would not be clear whether failure to submit a timely verification opinion was the responsibility of the verification body of the reporter.

H-50. Less Verification for Facilities With CEMS
Comment: Facilities with Continuous Emission Monitoring Systems (CEMS) subject to annual reporting should not be subject to annual third party verification. If CEMS are in use, annual verification is costly and redundant. [BVES(FF10)]

Agency Response: The Act required that the ARB develop a mandatory GHG emissions reporting program and that those emissions data reports be verified. The regulation incorporates third party verification modeled on international standards. Experience in California's voluntary program has shown that error often creeps into the emissions calculation and reporting process. Such errors may be reduced, but are not eliminated where CEMS are in place. Although we acknowledge the opportunity for automation of reporting that CEMS provide, some commenters have expressed concern with their accuracy where improper installations have occurred. We believe the matter of CEMS maintenance and quality assurance can be assisted through the verification process. For these reasons we reject the recommended change.

H-51. Provide Additional Time to Correct Misstatements of Nonconformance
Comment: Have some concern with the addition of the statement (Section 95131(c)(3)) that reads "shall be provided at least ten working days to modify the emissions data report to correct any material misstatement or nonconformance found by the verification team." Suggest a longer time of 30 calendar days or 20 working days. [Sempra(FF13)]

Agency Response: ARB added this language to provide a minimum specified period for the revision of the emissions data report. All reporters have the option to add language in their business contracts with verification bodies to increase the amount of time they believe may be needed to correct any material misstatements or nonconformance issues in order to receive a positive verification opinion. We do not support requiring a longer period by regulation.

H-52. Add Provisions to Eliminate Potential Redundancies with Local Districts

Comment: The South Coast Air Quality Management District already requires extensive monitoring and reporting measures from electric generating activities. It appears that the CARB regulation imposes extensive requirements without reference to existing local and regional reporting programs. Request that CARB add specific provisions in the proposed regulation to eliminate the potential for redundancy in GHG emissions monitoring, reporting, and verification between state and regional or local air district requirements. [BVES(FF10)]

Agency Response: The Act required ARB to develop a mandatory GHG emissions reporting program to be structured and implemented at the state level. Because of the global impact of GHGs and the desire for statewide consistency in reporting and verification requirements, a state program is appropriate. Air district authority to require reporting of air pollutants, including a choice on the part of some air districts to include GHGs in local reporting, is not affected by this new requirement.

The ARB regulation is designed to provide for facility-level emissions calculations sufficient to support a monetization of carbon-equivalent emissions. This fundamentally different purpose often requires quantification methods and verification procedures that vary significantly from air district monitoring and reporting requirements. We do not agree there will be significant redundancy in the procedures or the results of the two programs.

H-53. Harmonize AB 32 and CEQA Requirements

Comment: Recommend that ARB use the mandatory reporting rule to harmonize AB 32 and CEQA requirements, to provide certainty to government agencies and project proponents. [WSPA(FF17)]

Agency Response: ARB does not find the mandatory reporting regulation the appropriate venue for addressing the CEQA issues raised by AB 32. The Governor's Office of Planning and Research is developing CEQA Guideline updates, and in the context of their June 19, 2008 Technical Advisory, has asked ARB technical staff to recommend a method for setting CEQA thresholds that will encourage consistency and uniformity in the CEQA analysis of GHG emissions throughout the state. Current information is posted on the OPR website at this address: http://opr.ca.gov/index.php?a=ceqa/index.html.

H-54. Need for Future Revisions to Reporting Requirements

Comment: Encourage the ARB to consider the need for future refinements to the reporting regulations as it develops the Scoping Plan and overall AB 32 compliance program. [PGE(FF9)]

Agency Response: ARB agrees there will be need to revise the reporting regulation to support future emission reduction regulations and to eliminate reporting no longer needed.

H-55. Align with U.S. EPA National Reporting Requirements
Comment: Encourage the ARB to work with EPA as it develops the proposed national rules, and seek alignment between California's reporting regulation and EPA's national reporting program. [PGE(FF9)]

Agency Response: ARB is in consultation with U.S. EPA as it develops a national reporting program.

H-56. Provide Reporting Tool and Detailed Guidance
Comment: Commenter encourages the ARB to expeditiously develop a reporting interface, and to communicate, as soon as possible, the specific requirements for meeting April 2, 2009, reporting deadlines. Parties would benefit from as much detailed guidance as possible. . ." [PGE(FF9)]

Agency Response: ARB plans to provide a preview test version of the reporting tool for stakeholder review in the winter of 2008. ARB is also working on instructional guidelines with calculation examples to assist the reporting process. A first draft will be made available in early fall for stakeholder review.

15-DAY COMMENTS – SECOND RELEASE AND STAFF RESPONSES

For the second 15-day comment period several extremely targeted modifications and corrections were made to the regulation. In the notice of public availability it was specified that only these specific modifications were open for comment during the 15-day comment period. Four comment letters were received during the second 15-day comment period.

In the letter provided by Sempra [Sempra(FS1)], the comment related to exempting reporting for emergency fire pumps does not pertain to the specific changes included in the second 15-day changes provided for review, so we are not responding to that comment except to note that we intend to consider the question of excluding emergency fire pump engines from reporting in future updates to the regulation.

The second letter, from El Paso Corporation [ElPaso(FS2)], provided a variety of overall program comments, but these too were not directly related to the specific changes made in the 2nd 15-day comment period. The comments instead addressed historical issues related to the initial draft of the regulation and the first 15-day release. Responses are therefore not provided for the El Paso comments.

The letter from WSPA [WSPA(FS3)] does not provide comments related to the second 15-day changes, but states that issues raised in the first 15-day comments warrant clarification in the planned ARB instructional guidelines documents.

A final letter was received from Air Products [APC(FS4)] and the comments and staff responses are summarized below.

I-1. Support Clarification to Section 95103 for 5% Accuracy Standard
Comment: Support proposed clarification to limit application of 5% accuracy standard only to instances where fuel use measurement data are being used to directly calculate GHG emissions. [APC(FS4)]

Agency Response: No change is recommended by the commenter.

I-2. Extend of Fuel and Feedstock Reporting Limitation to Hydrogen Plants
Comment: In section 95113(a)(3) for refineries, support the change to limit fuel and feedstock consumption reporting to only when the data are used to directly calculate GHG emissions. Recommend that section 95113(a)(3) of the regulation be modified to extend the same fuel and feedstock reporting limitation to hydrogen production facilities. [APC(FS4)]

Agency Response: ARB agrees that it is not necessary for reporting facilities to report feedstock consumption unrelated to greenhouse gas generating processes. We believe this is already reflected in the regulation.

I-3. Clarify Applicability of CO_2 Method in Section 95125(h)(2)
Comment: It is unclear when method section 95125(h)(2) is applicable. May alternative methods for computing CO_2 emissions be used if waste-derived fuels are less than 30% by weight? Are the referenced percentages (e.g., 5% biomass and 30% waste derived fuels) based on annual average percent or a shorter term basis? Is the biomass content based on an individual fuel or mixture, or the total fuel stream combusted? (ARB Note: The comment letter refers to section 95125(h)(4). A section numbering error that occurred when the regulation was initially posted was quickly corrected. The comment clearly refers to the correctly numbered section 95125(h)(2). See next comment.) [APC(FS4)]

Agency Response: Section 95125(h)(2) specifically addresses the requirement to quantify and report the fraction of CO_2 combustion emissions from biomass fuels separately from the CO_2 emissions from fossil fuels. In general an operator who combusts fuel mixtures that contain biomass or waste-derived fuels that contain biomass will need to conduct a fuel analysis to determine the portion of CO_2 attributed to biomass. The fuel analysis methodology that is required, ASTM D6866-06a, is specified in section 95125(h)(2). It is feasible to use the methodology only when the total fuels being analyzed are at least 5% biomass. The expectation is that operators will know if their fuel mixtures are at least 5 percent biomass.

The regulation exempts certain operators from conducting this fuel analysis. The exemption applies to operators who combust fossil fuels with waste-derived fuels that include biomass when the waste-derived portion of the total fuel mixture is less than 30 percent by weight throughout the report year. For example, if the operator combusts no more than 20 percent tires and roughly 80 percent coal, the operator is exempt from doing the ASTM D6866-06a analysis. The waste-derived content of the fuel source must remain less than 30 percent throughout the report year for the exemption to apply. If the operator anticipates that the waste-derived content of the fuel source will fluctuate and exceed 30 percent at any time during the year, the operator is required to conduct the ASTM D6866-06a analysis every three months. When the operator claims the exemption, all fuels combusted will be categorized as fossil fuels. The operator will have forgone the option to claim any portion of fuels combusted as biomass-derived.

In the example, if the tires themselves are estimated to contain 15 percent biomass, then the overall total fuel mixture would have an estimated biomass content of 3 percent. This amount of biomass is too small to feasibly conduct the ASTM D6866-06a analysis. Also, if the operator co-fires pure biomass-derived fuels with fossil fuels, the operator will determine CO_2 emissions separately for the biomass using a fuel-based methodology. There is no need to conduct the ASTM D6866-06a fuel analysis.

The requirements in section 95125(h)(2) do not provide a method for computing the overall CO_2 combustion emissions for the fuels burned. The methodologies for this purpose are identified for each sector by fuel type in sections 95110 through 95115 of the regulation. If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a analysis for only one of the units.

I-4. Several Sections are Indexed Incorrectly

Comment: Some of the sections are incorrectly numbered, for example, some numbers were changed to letters, and letters changed to numbers. [APC(FS4)]

Agency Response: For a brief period of time (<12 hours) the initial posting of the revised regulation on the ARB website had numbering format misprints in which the section and subsection numbering were incorrectly formatted in some parts of the document. This was quickly corrected and the document was reposted. The misprints were not related to the substantive underline/strikeout changes in the regulation.