State of California
AIR RESOURCES BOARD

Final Statement of Reasons for Rulemaking

Including Summary of Comments and Agency Response

AMENDMENTS TO THE REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS AND CONFORMING AMENDMENTS TO THE DEFINITION SECTIONS OF THE AB 32 COST OF IMPLEMENTATION FEE REGULATION AND THE CAP-AND-TRADE REGULATION

Public Hearing Date: September 20, 2012
Agenda Item No.: 12-6-2

November 2, 2012

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I. Introduction

In this rulemaking, the Air Resources Board (ARB or Board) has adopted proposed revisions to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, section 95100 et seq.) (reporting regulation or MRR), as well as conforming amendments to the definition sections of the AB 32 Cost of Implementation Fee Regulation (title 17, California Code of Regulations, section 95200 et seq.) (fee regulation) and the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (title 17, California Code of Regulations, section 95800 et seq.) (cap-and-trade regulation). The regulations were originally developed pursuant to the California Global Warming Solutions Act of 2006 (the Act). The reporting regulation was adopted by the Board in December 2007, with additional modifications approved for adoption by the Board in December 2010. The fee regulation was first considered by the Board in September 2009, and went into effect on July 17, 2010. The cap-and-trade regulation was first considered by the Board in December 2010, and went into effect on January 1, 2012.

On August 1, 2012, ARB issued a notice of public hearing to consider the proposed amendments at the Board's September 20, 2012 hearing. A "Staff Report: Initial Statement of Reasons for Rulemaking" (Staff Report) was made available for public review and comment starting August 1, 2012. The Staff Report, which is incorporated by reference herein, contained a description of the rationale for the proposed amendments. The text of the proposed amendments was included as Attachments A, B, and C to the Staff Report. All references relied upon and identified in the Staff Report were also made available to the public on August 1, 2012. These documents were also posted to ARB's website at: http://www.arb.ca.gov/regact/2012/ghg2012/ghg2012.htm

At its September 20, 2012 public hearing, the Board considered staff's proposal for adoption. The proposed revisions to the regulations are necessary to support California's cap-and-trade program, as well as further harmonization with the U.S. Environmental Protection Agency (U.S. EPA) federal mandatory greenhouse gas (GHG) reporting requirements contained in Title 40, Code of Federal Regulations (CFR), Part 98. The revisions are also necessary, and authorized, to "prepare, adopt, and update" California's inventory of emissions related to climate change formerly conducted by the State Energy and Natural Resources Conservation and Development Commission pursuant to Chapter 8.5 (commencing with Section 25730) of Division 15 of the Public Resources Code. (California Health & Safety Code section 39607.4).

At the hearing, written and oral comments were received. The Board adopted Resolution 12-25, approving the revisions proposed in the Staff Report for adoption, with a small number of modifications proposed by staff.

In accordance with Government Code section 11346.8, in Resolution 12-25 the Board directed the Executive Officer to adopt the proposed regulations, with the modifications identified in the Resolution and other conforming modifications as may be appropriate, after making the modified language and any additional supporting documents available to the public for a comment period of no less than 15 days. Resolution 12-25 also directed the Executive Officer to consider written comments as may be submitted during this period, and to make such modifications as may be appropriate in light of the comments received, and to present the regulations to the Board for further consideration if the Executive Officer determined this was warranted in light of the comments received.

Further modifications to the reporting regulation, as well as to one definition in the fee regulation and cap-and-trade regulation, were released on October 12, 2012 in 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. The comment period extended from October 12, 2012 to October 29, 2012. These amendments clarify calculation methods, increase the rigor of provided data, and support cap-and-trade and the other AB 32 programs.

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 subsequently issued Executive Order R-12-014 on November 2, 2012, approving the regulation with the modifications described in Section II of this FSOR.

Fiscal Impacts to Local Governments and School Districts

The Executive Officer has determined that the proposed regulatory action will not result in a mandate to any local agency or school district, the costs of which are reimbursable by the state pursuant to Part 7 (commencing with section 17500), Division 4, Title 2 of the Government Code. The Board has also determined that this regulatory action will not create additional costs or impose a mandate upon any local agency or 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.

Some public local government agencies are subject to the current reporting regulation, such as certain county or city owned sewage treatment works or landfills, local municipal utility districts or electric retail providers. The proposed amendments are expected to result in an annual cost saving of approximately $4,900 ($2,500-$7,000) per year for nine local government entities operating electricity generating facilities that are subject to the federal Acid Rain Program (40 CFR Part 75) (U.S. EPA Part 75 2009). The cost saving is relative to the baseline case of maintaining the existing California greenhouse gas reporting regulation.

Economic Impacts on Small Businesses

There may potentially be one affected small business in each of the glass production sector, the iron and steel production sector, and the pulp and paper manufacturing sector. No affected small business entities are expected in any other remaining sectors. Any small businesses affected by the amendments will likely be eligible for abbreviated reporting and incur relatively less costs than their counterparts with higher emissions. Their annual cost is estimated to be in the $1,000 to $3,000 range.

Incorporation by Reference

As specified in the Staff Report, the following documents are incorporated into the regulation by reference: *Oil and Gas and Sulfur Operations in the Outer Continental Shelf*, 30 Code of Federal Regulations (CFR) Part 250, Subpart C (July 1, 2011 Edition); *Year 2008 Gulfwide Emission Inventory Study (GOADS)*, U.S. Department of the Interior, OCS Study, BOEMRE 2010-045 (December 2010); *Alternative Work Practice for Monitoring Equipment Leaks*, 40 CFR Part 60, Subpart A (July 1, 2011 Edition); *Method 21 – Determination of Volatile Organic Compound Leaks*, 40 CFR Part 60, Appendix A-7 (July 1, 2011 Edition); and *Regulation of Fuels and Fuel Additives*, 40 CFR Part 80.40, 40 CFR Part 80.41, and 40 CFR Part 80.27 (July 1, 2011 Edition).

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. In addition, some of the documents are copyrighted, and cannot be reprinted or distributed without violating the licensing agreements. 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 California Code of Regulations 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. Also, 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 available from college and public libraries, or may be purchased directly from the publishers.

Consideration of Alternatives

The proposed amendments were the subject of discussions involving staff, representatives of the affected businesses and agencies, and other interested members of the public. A detailed discussion of alternatives to the initial regulatory proposal, including supporting evidence, is provided in Chapter III of the Staff Report. Alternatives to the proposed regulations that were considered include: taking no action (i.e., retaining the existing rule) and directly adopting the U.S. EPA regulations for GHG reporting.

As mentioned in the Staff Report, anticipated benefits of the proposed amendments include improved clarity for reporting entities as to their reporting and verification obligations, more accurate GHG emissions estimates from corrected or updated emissions calculation methods and emission factors, improved clarity to support the statewide greenhouse inventory program and continued robust methods for reporting emissions and product data in order to support ARB's cap-and-trade regulation, fee regulation, and other GHG-related programs. These benefits may also have indirect beneficial impacts on the health and welfare of California residents, worker safety, and the state's environment by ensuring that the state has an accurate emissions inventory to support ARB's emission reduction measures.

For the reasons set forth in the Staff Report, in staff's comments and responses at the hearing, and in this FSOR, the Board determined that no alternative 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 as and less burdensome to affected private persons, or would be more cost-effective to affected private persons and equally effective in implementing the statutory policy or other provisions of law than the action taken by the Board.

II. Modifications Made to the Original Proposal

Modifications to the amendments proposed on August 1, 2012, as described in the Staff Report, were released concurrently on October 12, 2012. The amendments approved for adoption by the Board clarify calculation methods, increase the rigor of provided data, and support cap-and-trade and the other AB 32 programs. The modifications for public comment on October 12, 2012, made in light of comments received prior to and during the Board hearing, further clarify these calculation methods, increase the rigor of reported data, and support other AB 32 programs, including the cap-and-trade program.

As described above, a Notice of Public Availability of Modified Text, together with a copy of the modified text with modifications clearly indicated, was made available for review on October 12, 2012, with comments due on October 29, 2012. This notification was sent to persons who have expressed interest in the regulations during the course of the rule development and review, including all individuals described in subsections (a)(1) through (a)(4) of section 44, title 1, California Code of Regulations. By these actions, the modified regulations were made available to the public for a supplemental comment period pursuant to Government Code section 11346.8.

Summary of Proposed Modifications

Below, staff provides an overview of the modifications to the originally proposed regulations. The overview does not include modifications to correct typographical or grammatical errors, or changes in numbering or formatting, nor does it include all of the non-substantive revisions made to improve clarity. All references to sections 95101, 95102, 95103, 95104, 95105, 95111, 95112, 95113, 95114, 95115, 95119, 95120, 95121, 95122, 95123, 95130, 95131, 95132, 95133, 95150, 95151, 95152, 95153, 95154, 95155, 95156, 95157, 95158, 95202, and 95802 are to title 17 of the California Code of Regulations. Also, all references to sections of the regulation shown below are to the modified text included for the supplemental review and comment period, and not the originally proposed text.

These modifications to the regulations originally published August 1, 2012 were made available to the public for review and comment on October 12, 2012. The major changes are summarized below. For a complete account of all modifications to the proposed regulations, please refer to the double-underline and double-strikeout sections of the regulation in Attachments 1-3 to the Notice of Public Availability of Modified Text at the reporting regulation webpage at: http://www.arb.ca.gov/regact/2012/ghg2012/ghg2012.htm.

A. Modifications to Subarticle 1 General Requirements for Greenhouse Gas Reporting

This section of the regulation provides the general reporting requirements applicable to reporting entities. Below is a summary of some modifications to the regulation that apply to multiple sectors or reporting categories.

Modifications to Section 95101. Applicability.

Staff clarified the time needed to retain records once a facility has ceased reporting under the reporting regulation (§95101(h)). This change is necessary to ensure consistent requirements for record retention.

Modifications to Section 95102. Definitions.

In response to stakeholder comments and feedback, staff has proposed amendments to clarify definitions related to electric power entities (including the definition of “asset-controlling supplier”), electricity generation, and suppliers of transportation fuels.

Modifications to Section 95103. Greenhouse Gas Reporting Requirements.

Staff has added language to section 95103(f) to more clearly identify the verification requirements. Additional language was modified in section 95103(k) to clarify the existing meter calibration requirements and to emphasize the optional nature of the field accuracy assessments. These changes are necessary to ensure reporting entities understand the verification and meter calibration requirements of the regulation.

B. Modifications to Subarticle 2 Requirements for the Mandatory Reporting of Greenhouse Gas Emissions from Specific Types of Facilities, Suppliers, and Entities

This subarticle includes specific reporting requirements for each reporting sector, and for the stationary combustion reporting requirements that apply to multiple sectors. Revisions are summarized below.

Modifications to Section 95111. Data Requirements and Calculation Methods for Electric Power Entities.

In response to stakeholder comments, staff has made clarifying changes regarding electricity wheeled through California (§95111(a)(8)), Renewable Energy Credit (REC) retirement requirements (§95111(g)), and the retention of meter data from generation facilities (§95111(g)). These changes are needed to ensure electric power entities know what and how to report.

Modifications to Section 95121. Suppliers of Transportation Fuels.

Staff proposed clarifications suggested by stakeholder comments in sections 95121(a)(2) and 95121(d)(2) to more clearly describe reporting requirements for refiners, position holders, and enterers.

C. Modifications to Subarticle 5 Reporting Requirements and Calculation Methods for Petroleum and Natural Gas Systems

This subarticle incudes the reporting requirements for petroleum and natural gas systems. The proposed changes were made in response to stakeholder comments and consultation, and staff analysis. As in the original proposal released on August 1, 2012, these amendments are made to harmonize, to the extent feasible, with the U.S. EPA finalized reporting rule for Oil and Natural Gas Systems (Subpart W) by including that language directly in ARB's regulation, while also retaining the rigor that is needed for California's cap-and-trade program. Additional revisions are proposed that correct minor errors, provide clarification, and improve data quality.

Modifications to Section 95150. Definition of the Source Category.

Language regarding booster stations as they relate to this source category was inadvertently struck from section 95150(a)(3)-(4) during a previous amendment process and has been re-inserted. This change was made based in part on stakeholder comments, and also to ensure a complete and accurate definition of this source category.

Modifications to Section 95153. Calculating GHG Emissions.

Methods for the quantification of CH_4 and CO_2 emissions from produced water and crude oil and condensate have been edited and combined into a single section (§95153(v)) to ensure accurate emissions calculations. In addition, and based on stakeholder comments, staff has modified the pneumatic device methodology (§95153(a)) to allow for the use of alternative emission estimation methods for intermittent devices. Staff has also modified provisions related to equipment and pipeline blowdowns to allow for the use of engineering methods for pressure and temperature measurements (§95153(g)).

Additional changes were made to harmonize with the U.S. EPA greenhouse gas reporting rule. These changes include modifications to acid gas removal vents

(§95153(c)), associated gas venting and flaring (§95153(k)), and greenhouse gas volumetric emissions methods (§95153(s)). Finally, several typographic errors and incorrect section citations have been corrected.

Modifications to Section 95154. Monitoring and QA/QC Requirements.

Staff has proposed a modification to section 95154(f)(1) to more accurately describe the type of method that is allowed for best available monitoring methods. This change was necessary to clarify the reporting terminology.

Modifications to Section 95156. Additional Data Reporting Requirements.

In response to stakeholder comments, staff has proposed modifications to the reporting requirements for cogeneration plants associated with onshore petroleum and natural gas production facilities (§95156(a)(3)). These changes add clarity as to what must be reported for cogeneration sources. Also, staff has clarified the steam generator source terminology to more clearly describe the reporting requirement (§95156(a)(4)). Finally, staff has modified section 95156(e) to clarify that operation of natural gas processing facilities is included in this requirement.

Modifications to Section 95157. Activity Data Reporting Requirements.

Staff has proposed a modification in section 95157(c)(3) to more accurately reference the equations which must be used in reporting the information required by this section. This change was necessary to ensure accurate reporting.

D. Modifications to the AB 32 Cost of Implementation Fee Regulation and Cap-and-Trade Regulation.

As described above, staff has amended the definition of "asset-controlling supplier" in section 95102 of the reporting regulation. In order to ensure consistent use of terminology between the reporting regulation, fee regulation, and cap-and-trade regulation, staff has also proposed identical conforming amendments to the definition of "asset-controlling supplier" in the fee regulation and cap-and-trade regulation.

Non-Substantive Corrections to the Regulation

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 non-substantive changes listed below.

Corrections of strikeout and underline formatting: Certain areas of text were incorrectly underlined or struck out. In section 95111(g)(1)(M), the text "primary facility name, total number" should have been double-underlined in the 15-day changes; instead it was single-underlined.

Corrections to section 95153(p): Addition of the word "section" under the variable GHGi in Equation 27. The text should read, "…..as defined in paragraph (s)(2) of this section;" This change has been corrected by addition.

Punctuation corrections: A comma was inadvertently struck from 95153(y)(1) in the 15-day changes. This comma has been reinserted so that the second sentence reads: "If the fuel combusted is a natural gas and is of pipeline quality specification, use the calculation methodology described in paragraph (y)(1)(A) and the facility operator may use the emission factor provided for natural gas as listed in Subpart C, Table C-1."

III. SUMMARY OF COMMENTS AND AGENCY RESPONSE

The Board received numerous written and oral comments during the 45-day and 15-day comment periods for this regulatory action. Below is the list of commenters with a numeric identifier that corresponds with the identification number on the ARB website for submitted written comments, which are available here: http://www.arb.ca.gov/regact/2012/ghg2012/ghg2012.htm.

This rulemaking for amendments to the ARB mandatory reporting program, and conforming amendment to the definition sections of the fee regulation and the cap-and-trade regulation, was developed on a concurrent timeline because of the interrelationships between the three regulations. However, a few comments were submitted to this rulemaking which relate to other, separately noticed cap-and-trade rulemakings, outside of the scope of the proposals identified in the Staff Report, Notice of Modified Regulatory Text, and this FSOR. Statute only requires responses to comments directly submitted as part of a specific rulemaking, and this FSOR provides responsive comments only to those comments related to this specific rulemaking.

Individual comments are identified using a coding scheme to identify when the comment was received (e.g., as part of the initial 45-day comment period or during a 15-day comment period), the sequence number of the comment (generally based on the order in which it was received), a sub-sequence number if the comment contains more than one distinct comment, and an abbreviation for the commenter. For instance, in the example comment below, the comment was received as a letter at the board meeting, as part of the 45 day comment period. It was comment letter #03, and it is comment #02 of the letter. The commenter abbreviation is WSPA. This abbreviation code would be B 03.02 – WSPA. All submitted written comments for the mandatory reporting rulemaking are available here: http://www.arb.ca.gov/regact/2012/ghg2012/ghg2012.htm.

Example:

A-2. Applicability for Petroleum and Natural Gas Systems

Comment: Commenter notes new "process emissions" reporting requirement for facilities over the 10,000 MT CO_2e threshold, but finds the current definitions unclear as to what is considered process emissions versus vented emissions. [B 03.02 – WSPA]

When multiple comments were included within a single submittal, individual comments within the submittal were numbered sequentially to specifically identify them. For example, Board Submission letter #03 includes several comments, so within the responses, these individual comments are identified as 03.01, 03.02, 03.03, etc.

The table below describes the prefixes used to indicate when the comments were received during the rulemaking process.

Code	Comment Received Description
OP	Comment numbers prefixed with an “OP” are comments received on the “Original Proposal” during the initial 45-day comment period.
B	Comment numbers prefixed with “B” are written comments provided at the “Board” hearing on September 20, 2012.
T	Comment numbers prefixed with “T” were public “Testimony” provided verbally at the Board hearing on September 20, 2012.
F	Comments Numbers prefixed with “F” were received during the “Fifteen” day comment period.

The following table provides a summary of all of those providing comments. Following the lists, each comment is summarized, generally organized by subject area, and not commenter, and a response is provided explaining how the proposed action has been changed to accommodate the comment, or the reason(s) for making no change.

List of Commenters and Abbreviations
– Original Proposal –

Comment Number	Abbreviation	Commenter
OP01	WPTF	Breidenich, Clare, Western Power Trading Forum
OP02	TA	Boulanger, Braydon , TransAlta
OP03	PG&E	Krausse, Mark, Pacific Gas and Electric
OP04	NA	Corr, Thomas, Noble Americas
OP05	GEA	Gawell, Karl, Geothermal Energy Assn
OP06	SCPPA	Pedersen, Norman, So. California Public Power Authority
OP07	LML	Moreno-Linares, Lucia, Wilmington resident
OP08	SCE	Allred, Nancy, Southern California Edison
OP09	GPI	Buchan, Bill, Graphic Packaging Int, Inc.
OP10	TA	Boulanger, Braydon , TransAlta
OP11	LSP	Chamberlin, Jennifer, LS Power
OP12	APS	Kafka, Michal, Arizona Public Service
OP13	LTC	Ruscio, Marcus, Lunday-Thagard Company
OP14	CC	McBride, Barbara , Calpine Corporation
OP15	CEOC	Parker, Craig, CalEnergy Operating Corporation
OP16	CCEEB	Lucas, Robert, California Council for Environmental and Economic Balance
OP17	LADWP	Parsons, Cindy, LADWP
OP18	JD	Dillard, Joyce, concerned citizen 2
OP19	PX	van Aelstyn, Nicholas, PowerEx
B01	CIPA	Plotkin, Norman, California Independent Petroleum Assn.
B02	SE	Rasberry, Tamara, Sempra Energy
B03	WSPA	Reheis-Boyd, Catherine, WSPA
T01	WSPA	Reheis-Boyd, Catherine, WSPA
T02	CEOC	Parker, Craig, CalEnergy Operating Co.
T03	SCE	Harris, Frank, Southern California Edison
T04	SWC	Haines, Tim, State Water Contractors
T05	SCPPA	Pedersen, Norman, So. California Public Power Authority
T06	APS	Kafka, Michael, Arizona Public Service
T07	PG&E	Krausse, Mark, Pacific Gas & Electric

List of Commenters and Abbreviations
– 15-Day Proposal –

Comment Number	Abbreviation	Commenter
F01	GPI	Buchanan, Bill, Graphic Packaging Int, Inc.
F02	MS	Steube, Milan
F03	WSPA	Reheis-Boyd, Catherine, WSPA
F04	SCPPA	Mitchell, Lilly, So. California Public Power Authority
F05	LADWP	Parsons, Cindy, LADWP
F06	SCG	Johnson, Darrell, Southern California Gas Company

45-DAY COMMENTS AND STAFF RESPONSES

A. Subarticle 1. Applicability, Definitions, and General Requirements (§95100 – §95105)

§95100 – Purpose and Scope

No changes were proposed to section 95100, and no comments were received on section 95100.

§95101 – Applicability

A-1. Record Retention

Comment: Cessation of Reporting indicates that records must be retained for "… each of the five consecutive years and retain such records for five years…" We believe this should say records must be retained for "… each of the three consecutive years and retain such records for five years…" [B 01.01 CIPA]

Response: ARB staff agrees with the comment. The text has been modified in the 15-day proposal.

A-2. Applicability for Petroleum and Natural Gas Systems

Comment: Commenter notes the new "process emissions" reporting requirement for facilities over the 10,000 MT CO_2e threshold, but finds the current definitions unclear as to what is considered process emissions versus vented emissions. [B 03.02 – WSPA]

Response: Section 95102(a) of the reporting regulation defines "process emissions" (section 95102(a)(306)) and "vented emissions" (section 95102(a)(404)). A clear distinction between the definitions is that process emissions are used to describe non-combustion emissions that occur due to a chemical or physical process (such as calcination of carbonates), whereas vented emissions refers to the release of CH_4- or CO_2- containing natural gas into the atmosphere.

§95102 - Definitions

A-3a. Asset Controlling Supplier (ACS)

Comment: PG&E contends that an asset-controlling supplier cannot be assigned a specified source emission factor because it is not a specified source but rather the owner, operator, or marketer of a number of sources. Therefore, PG&E proposes to replace the term "specified source" in the ACS definition with the term "system" to conform with the methodology for calculating the system emission factor for an asset controlling supplier, as described below:

> "Asset-Controlling Supplier" means any entity that owns or operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them, and is assigned a supplier specific identification number and ~~specified source~~ system emission factor by ARB for the wholesale electricity procured from its system and imported into California."

[OP 03.07 – PG&E]

Response: ARB staff agrees with PG&E and this change was made in the 15-day changes to establish consistency in the use of the term throughout the regulation. For example, section 95111(b)(3), *Calculating GHG Emissions of Imported Electricity Supplied by Specified Asset-Controlling Suppliers*, requires ARB to calculate and publish a "system emission factor."

A-3b Asset Controlling Supplier (ACS)

Comment: WPTF poses a question regarding the boundary conditions for registration as an ACS. The reporting requirements for ACS as set out in section 95111(f) seem to anticipate that an ACS fleet would comprise a single 'system', but the term 'system' is not defined in the regulation. WPTF understands that ARB's intent is that ACS registration is available to entities that own, operate or exclusively market resources that are interconnected within a single balancing area – the output of these resources could then be mixed and directly delivered to California on a single tag. WPTF therefore recommends that this requirement be explicitly stated in the regulation, as shown below:

> (~~17~~19) "Asset-controlling supplier" means any entity that owns or operates inter-connected electricity generating facilities or serves as an exclusive marketer for ~~certain generating~~ these facilities even though it does not own them, and is assigned a supplier-specific identification number and ~~specified source~~ system emission factor by ARB for the wholesale electricity procured from its system and imported into California. ~~Bonneville Power Administration (BPA) is recognized by ARB as an asset-controlling supplier.~~

[OP 01.02 – WPTF]

Response: ARB accepts the WPTF edits to the ACS definition, except for the "within the same balancing area" phrase that would have followed the term "inter-connected," for the reason that, although some ACS applicants may control a fleet of resources that are physically located within the same balancing authority area and are capable of physically combining and directly delivering power from the ACS fleet to California on a single tag, some ACS resources may to a small degree span more than one balancing area.

A-4. Basin Definition Map References

Comment: A concerned citizen, Ms. Joyce Dillard, questions why the term "hydrocarbon basin" is limited to maps which are not readily available to the public and are determined by an industry association. The commenter further states that "it is the contamination factor, and the heating factor or sea-level rise that are important in the emissions." [OP 18.01 – JD]

Response: The hydrocarbon basin definition, as it relates the definition of "facility," was incorporated directly from U.S. EPA's rule. The basin boundaries in most cases follow California county boundaries, and are not in any way related to groundwater basin plans as the commenter suggests. While we are unsure what information the commenter is referring to, a "contamination factor, a heating factor, or considerations of sea-level rise" were not part of the consideration concerning facility reporting footprints or greenhouse gas reporting methodologies. ARB staff will add a list to the reporting regulation website to indicate to reporters and interested parties which counties are in each of the hydrocarbon basins in California.

A-5a Electricity Importer

Comment: SCPPA supports the proposed changes to the definition of "electricity importer" but states that the definition should be further revised to clarify which entity is considered to be the electricity importer in the event there is no NERC e-Tag. Currently, the definition refers to "the facility operator or scheduling coordinator" without specifying the order of priority of those two types of entities. SCPPA contends that this could lead to confusion in cases where there is no NERC e-Tag, but there is both a scheduling coordinator and a separate facility operator. Specifically, SCPPA requests revising the definition of "electricity importers" as follows:

(140) "Electricity importers" deliver imported electricity. For electricity that is scheduled with a NERC e-tag to a final point of delivery inside the state of California, the electricity importer is identified on the NERC e-Tag as the purchasing-selling entity (PSE) on the last segment of the tag's physical path with the point of receipt located outside the state of California and the point of delivery located inside the state of California. For facilities physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission or~~and~~ distribution system when the electricity is not scheduled on a NERC e-Tag, the importer is the ~~facility operator or~~ scheduling coordinator or the functional equivalent, or if there is no entity performing this function, the facility operator. Federal and state agencies are subject to the regulatory authority of ARB under this article and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and California Department of Water Resources (DWR).

[OP 06.03 – SCPPA]

Response: By design, this language identifies "the facility operator or scheduling coordinator" so that market participants are free to negotiate this provision as part of any electricity transaction. However, when neither market participant accepts responsibility as the electricity importer, ARB has the option to apply that responsibility to either or both entities. Therefore, ARB believes that the existing language is sufficient and declines to make the requested changes.

A-5b Electricity Importer

Comment: LS Power contends that ARB should not rely solely on e-tags to determine the electricity importer (first deliverer) when power flows across balancing authority areas that may span the California border, because e-tags were never intended to serve as a mechanism to track the ownership of power. LS Power states that there are many instances when a seller is listed as the PSE on the physical path, even though delivery occurred (and title transferred) outside California. According to LS Power, even though the power may eventually come into California, ARB's jurisdiction cannot extend to the sellers in these instances where the transaction is completed outside California without offending the Commerce Clause. LS Power cites to various case law to support its Commerce Clause concerns. As a remedy, LS Power proposes (1) edits to the "electricity importer" definition (as shown below) which consist of adding in the concept of 'title to power' in order to determine the electricity importer and thus the first deliverer, and (2) that ARB schedule future workshops to identify new mechanisms for tracking electricity imports that may or may not include e-tags or "new tracking mechanisms and software that are specifically designed to accommodate the cap-and-trade program and that would be used by all importers to ensure a level playing field." Specifically, LS Power requests the following changes to the definition of "electricity importer" in both the reporting regulation and cap-and-trade regulation:

(87) "Electricity Importers" ~~are marketers and retail providers that~~ deliver imported electricity. For electricity that is scheduled with a NERC e-Tag to a final point of delivery inside the state of California ~~delivered between balancing authority areas,~~ the electricity importer ~~is~~ **may be** identified on the NERC e-Tag as the purchasing-selling entity (PSE) on the last segment of the tag's physical path with the point of receipt located outside the state of California and the point of delivery located inside the state of California. **When an entity delivers power to a point located out of state, the electricity importer is the entity that holds title to the electricity on the physical transmission path crossing the California border, which may be determined by contract, settlement data or other relevant information presented to a verifier pursuant to the Mandatory Reporting Regulation**." For facilities physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission and distribution system when the electricity is not scheduled on a NERC e-Tag, the importer is the facility operator or scheduling coordinator. Federal and state agencies are subject to the regulatory authority of ARB under this article and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and California Department of Water Resources (DWR).

[OP 11.01 – LSP]

Response: In drafting the reporting regulation, ARB concluded that the existing NERC e-Tag system used to support reliability standards for the North American bulk power system provides consistent and reliable source data and independent documentation of electricity delivered across balancing authority areas. NERC is the electric reliability organization (ERO) certified by the Federal Energy Regulatory Commission to establish and enforce reliability standards for the bulk-power system. NERC develops and enforces reliability standards; assesses adequacy annually via a 10-year forecast, and summer and winter forecasts; monitors the bulk power system; and educates, trains and certifies industry personnel.

When electricity is delivered across balancing authority areas (BAAs), NERC e-Tags are created to request, approve, and document the interchange transaction from source (generation) to sink (load), designating the market path and physical path from first point of receipt (POR) to final point of delivery (POD). Therefore, for electricity that crosses BAAs, imports, exports, and wheels are defined pursuant to subsection 95102(a) with respect to the location of the first POR the final POD as documented on NERC e-Tags. This convention, based on *NERC Reliability Standards* and supporting business practices, provides for rigorous and consistent accounting of emissions from electricity.

Purchasing-selling entities are designated on NERC e-Tags for each segment of the physical transmission path, which provides the means for reporting entities to clearly identify the quantities of electricity they import, export, and wheel across the California border. Subsection 95105(d) provides clear direction to use NERC e-Tags to document these transactions, as it is necessary for consistent reporting and verification. Market participants bidding into the CAISO markets are required to document electricity deliveries via NERC e-Tags, pursuant to CAISO Tariff section 4.5. Determining which transactions are specified or unspecified relies on written power contracts (and supporting records), settlements data, and invoices.

Regarding the commenters' concerns over the word "title," ARB notes that it modified the definitions of "electricity importer," "electricity exporter," "purchasing-selling entity," and "marketer" during the course of rulemaking in 2010 to clarify that delivery, and not title, is the critical determinant of responsibility recognized by ARB. ARB must rely on a clearly identifiable and verifiable entity that delivers electricity into California. Which party holds title to electricity may become a matter of dispute between counterparties and does not provide the certainty needed in a mandatory GHG reporting program, which serves as the underlying basis of the cap-and-trade program.

When marketers submit energy bids to the CAISO and the bids are accepted by CAISO, the market participants are required to submit NERC e-Tags to document their delivery to a registered CAISO load point. While the price of electricity may be determined at an out-of-state trading hub or locational marginal price node, financial transactions with CAISO require physical delivery (an interchange transaction) into California.

CAISO market participants that deliver energy across balancing authority areas are required to register with CAISO as scheduling coordinators and also register their load delivery points (first/final points of delivery) inside the state of California. These requirements are specified in the CAISO Tariff section 4.5, Operating Procedures, Scheduling Coordinator Agreement, and other business practices available on CAISO's website. ARB believes these reporting requirements ensure accurate reporting of imported electricity delivered into the state of California and that both in-state and out-of-state entities delivering power into California are treated equitably; as such ARB believes that the design and implementation of these requirements adequately address the legal concerns raised by LS Power. ARB therefore continues to decline to make the change suggested by LS Power.

ARB also notes that the amendments to the cap-and-trade regulation made in this rulemaking are limited to the definitions section only. As such, to the extent the comment raises other cap-and-trade related issues, those are outside the scope of this rulemaking and not addressed in this response.

A-6. <u>Facility</u>

<u>Comment:</u> Commenter recognizes ARB's definition of "facility" for onshore petroleum and natural gas production facilities and has already applied it to their industry. The commenter would like ARB to modify the definition to include the term "associated with a single well pad" instead of "associated with a well pad." The commenter indicates that the two descriptions are similar and indicates that U.S.EPA supports this in their responses to comments. CIPA would like to also see ARB define the term 'associated with a well pad.' [B 01.02 – CIPA]

Response: The facility definition for the onshore petroleum and natural gas production industry segment was adopted by U.S. EPA after much discussion and stakeholder input. ARB subsequently adopted this definition as the best approach to quantify emissions from an industry segment such as oil and gas production which is geographically widely dispersed. Under this approach, emissions from all sources "associated with a well pad" must be reported. U.S. EPA subsequently (December 2011) modified the requirement to read emissions "associated with a single well pad." ARB chose not to adopt this modification because it would have resulted in fewer emissions being reported and it was not consistent with goals of the cap-and-trade program in California. Discussions between ARB and U.S. EPA supported the conclusion that "associated with a well pad" would lead to collecting more emissions data at an onshore petroleum and natural gas production facility than moving towards the narrower "associated with a single well pad" phrase.

ARB staff believes that section 95150(a)(2) adequately addresses the phrase "associated with a well pad," as revisions proposed for that section include a parenthetical after the term "associated with a well pad" that describes the unit types associated with a well pad. As such, ARB declines to include a separate definition for "associated with a well pad."

A-7. Field Accuracy Assessment
Comment: The comment supports the addition of this definition, however, requests that staff remove the words "if possible" from the definition of field accuracy assessment. [B 03.01 WSPA]

Response: ARB agrees with the comment and made the suggested change.

A-8a. Generation Providing Entity (GPE)
Comment: SCPPA supports the proposed changes to the definition of generation providing entity, but states that the language, "recognized by ARB," should be removed (shown below) from the definition because ARB does not have a formal process to recognize GPEs.

(216) "Generation providing entity" or "GPE" means a facility or generating unit operator, full or partial owner, party to a contract for a fixed percentage of net generation, sole party to a tolling agreement with the owner, or exclusive marketer ~~recognized by ARB~~ that is either the electricity importer or exporter with prevailing rights to claim electricity from the specified source.

[OP 06.04 – SCPPA]

Response: ARB staff believes that the identification of GPEs, "recognized by ARB," is possible under the current regulatory structure, and ARB will work with stakeholders to ensure they understand this recognition process. Accordingly, ARB declines to make the requested change and the language "recognized by ARB" will remain in the GPE definition for implementation as described below.

As part of implementation, beginning in reporting year 2013, all electric power entities (EPEs) will be designated as GPEs unless or until a non-GPE status is demonstrated through the annual reporting process. For example, an EPE with one small share of a generation source would be recognized by ARB as a GPE, whereas an EPE that reports only unspecified power would not be recognized as a GPE. EPEs with ownership interests in generation resources are GPEs as prescribed by the definition. The burden of proof is on EPEs to prove or demonstrate that they are not GPEs during the annual reporting process.

Section 95111(a)(4) on Imported Electricity from Specified Facilities or Units states that each "*electric power entity must report all direct delivery of electricity as from a specified source for facilities or units in which they are a generation providing entity (GPE) or have a written power contract to procure electricity*." An EPE with a written power contract (or power contract) for a share of a generation resource would be recognized as a GPE, because that contract is for a "*fixed percentage of net generation from the facility or generating unit [or a] tolling agreement*." For example, an EPE with a contract for 50% of the output of the Power Plant ABC that has a total capacity of 1000 MW would be considered a GPE, whereas another EPE that simply has a specified source contract with Power Plant ABC for 300 MW would not be recognized as a GPE.

EPEs designated as GPEs must report facility registration information required in section 95111(g)(1) because they have more knowledge and information of the facility or unit under contract.

GPEs have a regulatory responsibility to claim power from GPE resources imported to California as from a specified source. The absence of e-tags does not absolve any EPE that does not use e-tags from the responsibility under the regulation to claim power as from a specified source as a generation providing entity. Section 95111(a)(4) requires that all direct delivery of electricity from a generation providing entity (GPE) must be reported as from a specified source. Power from a specified source can be claimed based on information other than e-tags. Section 95131(b)(6) states that the verification process shall include, but is not limited to, among other things, "*e-Tags, written power contracts, settlements data, and any other applicable information required to confirm reported electricity procurements and deliveries*." Thus, as a generation providing entity, EPEs must claim and report power directly delivered to California as from a specified source. In the absence of e-tags, EPEs are required to document specified source claims using "settlements data, and any other applicable information required to confirm reported electricity procurements and deliveries." There is no option under the regulation for an EPE to claim unspecified power that is directly delivered from a GPE.

A-8b. Generation Providing Entity (GPE)

Comment: APS stated that there is a lack of clarity in the regulations regarding the process by which electric power entities determine their emissions reporting status among the following options: unspecified source of electricity, generation providing entity, and asset controlling supplier. Specifically, APS states: “Some entities may fit within the definitions of ‘asset controlling supplier’ and ‘generation providing entities,’ while also importing power that meets the definition for ‘unspecified source of electricity.’ … “Without clear guidance, EPE’s are required to decide how to report emissions at the risk of discretionary enforcement for up to eight years after report verification. The risk and uncertainty involved may prevent entities from directly importing electricity into California, causing marketplace constraints that could be prevented through increased clarity within the regulations. PROPOSED RECOMMENDATION: Add clarity to the regulations to give EPEs clear instruction to know whether they must register as an Asset Controlling Supplier or a Generation Providing Entity versus when utilizing the unspecified source of electricity is acceptable.” [OP 12.02 – APS]

Response: See Responses to A-15a and A-15b for unspecified source of electricity, Response to A-8a generation providing entity, and Response to A-3a for asset controlling supplier definition clarifications.

A-8c. Generation Providing Entity (GPE)

Comment: WPTF states that the proposed revised definition should be improved to clarify that more than one entity may be considered a generation providing entity. According to the commenter, in the event that claims to a particular generation resource exceed actual facility generation, the documentation of contract terms and settlement data provided by entities claiming a particular percentage or amount from a generation source should be sufficient to accurately apportion a facility’s total available output to specific claimants, without the need to negate any individual entity’s claim, in order to avoid over subscription for reporting purposes. The definitional change is shown below:

> *(182) “Generation providing entity” or “GPE” means a facility or generating unit operator, full or partial owner, party to a contract for a fixed percentage of net generation <u>from the facility or generating unit</u>, ~~sole~~ party to a tolling agreement with the owner, or exclusive marketer recognized by ARB that is either the electricity importer or exporter with prevailing rights to claim electricity from the specified source.*
> [OP 01.07 – WPTF]

Response: ARB staff agrees with the edits to the GPE definition proposed by WPTF, which are reflected in the proposed 15-day modifications.

A-9. Net Generation

Comment: The proposed change to this definition would significantly increase the level of effort needed to calculate unit net generation, especially for facilities with more than one generating unit, and data needed to calculate net generation in accordance with the proposed amendment may not be readily available. In addition, the resulting difference in reported net generation would likely be de minimis (very small). LADWP recommends that this amendment be rejected because of the significant additional reporting burden and feasibility issues. LADWP's specific changes are shown below:

> *(~~257~~303) "Net generation" or "net power generated" means the gross generation minus station service or unit service power requirements ~~(during time periods when the generating unit is generating electricity)~~, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.*

[OP 17.01 – LADWP]

Response: Staff agrees with LADWP's assessment and revised the rule language as suggested by LADWP.

A-10. Primary Refinery Products

Comment: Request from commenter to clarify the meaning of "finished" which was added to the definition during the original proposal. [B 03.08 – WSPA]

Response: This language was added to correct a typographical error in definition of "primary refinery products." In section 95102(a)(243) of the reporting regulation, the definition of "motor gasoline (finished)" includes the word "finished." For consistency, the term was also added to the definition of "primary refinery products."

A-11. Product Data

Comment: Request from commenter to clarify meaning of product data for the purposes of petroleum and natural gas systems.

WSPA recommends ARB include a definition of "product" as follows:

> "Product means a commodity produced and used on site or sold to a third party by a facility … "
>
> Alternatively, WSPA recommends ARB identify which specific data points are considered product data for MRR purposes.

[B 03.03 – WSPA]

Response: The definition of "product data" (section 95102(a)(311)) of the reporting regulation) was not changed or noticed in the Initial Statement of Reasons and is therefore outside the scope of this rulemaking. However, in order to address the comment, ARB staff notes that product data includes all data that is needed to support the cap-and-trade program in addition to product data that is required to be reported in the U.S.EPA reporting rule. Any changes to this definition would require additional rulemaking. ARB staff will continue working with stakeholders to ensure that these product data reporting requirements for specific sectors are understood.

A-12a. Power Contract or Written Power Contract

Comment: WPTF contends that the reporting regulation does not provide sufficient detail with respect to conditions under which a written power contract entitles an electric power entity to claim electricity from a specified source. Although it did not propose any changes to the existing power contract definition, WPTF recommends that ARB add a new definition of 'specified power contract' to the MRR and use this term in operational provisions that apply to specified imports, which WPTF describes here:

> "The MRR currently contains a definition of "power contract" that is used in reference to both specified and unspecified sources of electricity. Because of this broad usage, the definition provides no clarity as to what conditions would make a contract eligible for claiming specified imports. Explanations from ARB staff suggest that there is an expectation that a power contract must be unit specific, but this is not explicitly articulated anywhere in the MRR. Further, the proposed revised definition of 'unspecified source of electricity' suggests that to be claimed as a specified source, the generation source must be known at the time of entry into the transaction to procure electricity. To eliminate any confusion, WPTF recommends that ARB add a new definition of 'specified power contract' to the MRR and use this term in operational provisions that apply to specified imports:
>
> "Specified power contract" means a power contract that is contingent upon delivery of power from a particular facility, unit, or asset-controlling supplier's system that is designated at the time the transaction is executed. [OP 01.05 – WPTF]

Response: ARB appreciates WPTF's overall support of the proposed 45-day changes to the power contract definition. In response to WPTF's early-filed comments, several stakeholders (TransAlta, SCPPA, and SCE) specifically supported WPTF's proposed specified power contract definition in their respective comments. In the MRR, the definition of power contract or written power contract is used for "*purposes of documenting specified versus unspecified sources of imported and exported electricity*. Thus, it was appropriate to augment the definition with more information about what exactly constitutes a power contract for a specified source, in order to more clearly make this distinction. Accordingly, ARB opted to incorporate the "specified power contract" definition proposed by WPTF into the existing definition of power contract in the 15-day changes.

A-12b. Power Contract or Written Power Contract

Comment: SCPPA proposes a number of edits to the definition of power contract, and noted that it would be helpful to have a definition of specified power contract as proposed by WPTF.

> "SCPPA supports the proposed changes to the definition of "Power contract." However, certain changes to this definition would increase its clarity. First, two terms are used for the same concept: "power contract"

and "written power contract." Only one term should be used for each defined concept. The term "power contract" is preferable. The term "written" is confusing, given that verbal and electronic records also qualify. References to "written power contract" in the MRR should be changed to "power contract." Second, the reference to "procurement of electricity" in the opening sentence of the definition is somewhat limiting. The examples of power contracts given in the second sentence go beyond procurement. The broader term "electricity transaction" should be used instead." SCPPA suggests the following changes:

> (351) "Power contract," ~~or "written power contract,"~~ as used for the purposes of documenting specified versus unspecified sources of imported and exported electricity, means an agreement ~~written document~~, including written, ~~associated~~ verbal or electronic records ~~if included as part of the written power contract~~, arranging for ~~the procurement of~~ an electricity transaction. Power contracts may be, but are not limited to, power purchase agreements, enabling agreements, and tariff provisions, without regard to duration, or ~~written~~ agreements to import or export electricity on behalf of another entity, as long as that other entity also reports to ARB the same imported or exported electricity under section 95111(c)(4) or section 95111(a)(6).

[OP 06.05 – SCPPA]

Response: SCPPA offered additional clarifying edits in early-filed comments which were subsequently supported by TransAlta, SCE, and LADWP. ARB accepted the addition of the term "or export" to definition. ARB concluded that the concept of a written power contract or written agreement must be maintained in the power contract definition. However, ARB understands and acknowledges that verbal and electronic records are regularly utilized as part of the electricity procurement process which may include, for example, electronic writing as described in the Western Systems Power Pool (WSPP) Agreement. The power contract definition acknowledges this form of recordkeeping. ARB believes that the 15-day changes address the commenter's concerns.

A-12c. Power Contract or Written Power Contract

Comment: SCE expresses its support for a revised power contract definition:

"SCE recommends that the ARB should better define a "power contract" when claiming electricity imports from a specified source. SCE shares other commenters' concerns that the current definitions and reporting requirements require additional clarity for compliance entities as well as third-party verifiers, regarding how an entity can claim electricity imports from a specified source and count the corresponding emissions at a source-specific emissions rate. In this regard, SCE supports WPTF's recommended definition that a "specified power contract" should mean a power purchase agreement that is contingent upon delivery of electricity from a specific unit or facility, or from an asset-controlling supplier's system, designated at the time of entry into the transaction to procure the electricity." [OP 08.07 – SCE]

Response: See responses A-12a and A-12b.

A-12d. Power Contract or Written Power Contract

Comment: TransAlta also supports additional changes to the MRR that provide clarity. In particular, TransAlta supports WPTF's recommendation that ARB add a new definition of 'specified power contract' to the MRR and use this term in operational provisions that apply to specified imports. [OP 10.01 – TA]

Response: See responses A-12a and A-12b.

A-12e. Power Contract or Written Power Contract

Comment: LADWP indicates that the "definition of power contract is key in determining whether to report imported electricity as specified or unspecified, so it needs to be crystal clear. LADWP supports the additional clarifications recommended in SCPPA's written comments dated September 14, 2012." However, ARB notes that LADWP did not comment on the new definition of specified power contract proposed by WPTF. LADWP stated that "while LADWP supports ARB's proposed amendment to the definition of power contract, LADWP believes the proposed amendment does not go far enough to clarify this important definition which is a key element in the determination of whether imported electricity can be reported as specified or unspecified" [and] "LADWP encourages ARB to adopt the amendments proposed by SCPPA" (See Comment A-12b). [OP 17.02 – LADWP]

Response: See responses A-12a, and A-12b.

A-13. Refiner

Comment: The commenter recommends that ARB include the following new definition in Section 95102(a). *"Refiner" means an individual entity or a corporate wide entity responsible for the reporting of transportation fuels required in this article."* [B 03.09 – WSPA]

Response: ARB agrees with the commenter, and added the definition of the term refiner in the 15-day language, with slight modifications from the recommended above, for the sake of consistency with the remainder of the regulation.

A-14. Sales Oil

Comment: The commenter indicates that the definition of "sales oil" does not clearly include oil that is trucked to a third party receiving facility where custody transfer occurs. The suggestion is to change the phrase "custody transfer tank gauge" to "other point of custody transfer" for the sake of specificity. [B 01.03 – CIPA]

Response: ARB staff believes that the quantity of sales oil to be reported is that which is recorded at the custody transfer point. As such, ARB staff believes the current language is sufficient and declines to make the suggested modification to this definition.

A-15a. Unspecified Source of Electricity

Comment: Section 95102(a)(471) of the Proposed MRR Amendments amends the definition of “unspecified source of electricity” to a “source of electricity that is not a specified source at the time of entry into the transaction to procure the electricity.” SCE states that the revised definition is simpler and clearer than the definition proposed in the previous draft of the regulation. SCE supports this modification and offers no suggestion for improvement at this time. [OP 08.07 – SCE]

Response: ARB appreciates SCE’s support on this issue.

A-15b. Unspecified Source of Electricity

Comment: WPTF agrees with the revised definition of unspecified source of electricity, but considers that, in the event that NERC tags are used to assign emissions for imports instead of contracts, it should apply symmetrically to both high and low emission power. Thus, if an importer purchases “Schedule C” power from the Intercontinental Exchange, that power should be assigned the default emission rate, regardless of whether the NERC tag shows the power as originating from a coal facility, or from the system of a low-emission ACS, such as Bonneville Power Administration. [OP 01.07 – WPTF]

Response: ARB appreciates WPTF’s support. Because NERC tags are not used to assign emissions for imports, whereas contracts are, ARB believes the regulation already addresses WPTF’s concern. In order to claim power from an asset controlling supplier, a reporting entity must meet the requirements set forth in the specified source definition and the provisions of section 95111.

A-16. Overall Support for Definitional Changes

Comment: This commenter supports the efforts of ARB staff to add clarity to the regulatory definitions. [OP 03.04 – PG&E]

Response: ARB staff appreciates the recognition of their efforts.

A-17. Definitional Clarifications

Comment: SCPPA would appreciate clarification and expansion of several definitions as we have recommended in our 45-day written comments. [T 05.04 – SCPPA]

Response: Please see the Responses to A-5a, A-8a, A-12b, B-3a, and B-13c.

A-18. Measurement Accuracy Requirements.
Comment: Commenter suggests updating the language in section 95103(k) "to assure clarity for reporters and verifiers." They want to add the following sentence to the list of reporters not subject to the requirements: "stationary fuel combustion units that report using methods in 40 CFR §98.44." The commenter goes on to voice objection over the photography requirement for orifice plates in section 95103(k)(6)(A)(1)(b). [OP 03.07 – PG&E]

Response: ARB believes that changes to section 95103(k) in the 45-day language already include the Part 75 exclusion suggested by the commenter. Regarding the second part of the comment, ARB determined that the photographic evidence requirement is minimally burdensome and should not be excluded based on the type of gas being measured, so no change was made.

A-19. Flow measurement.
Comment: The commenter believes it would be helpful to include the various meter calibration options operators may have used prior to January 1, 2012 to meet compliance with 95103(k) meter calibration requirements. WSPA recommends specific language be added to section 95103(k)(3) as follows:

(3) For facilities and suppliers that become subject to this article after January 1, 2012, all flow meters and other measurement devices that provide data used to calculate GHG emissions or product data must be installed and calibrated no later than the date on which data collection is required to begin under this article. ***However, flow meters and measurement devices that were calibrated prior to January 1, 2012, based on either the requirements of the 2007 version of the mandatory reporting regulation, manufacturer's recommended procedures, or methods specified in 40 CFR Part 98, would not be required to conduct future re-calibrations provided the time interval between successive calibrations specified in 95103(k)(4) has not elapsed.***

[B 03.04 – WSPA]

Response: ARB staff agrees with the comment and has made changes in the 15-day package to section 95103(k)(1) consistent with the commenter's suggested additions.

A-20. Meter Accuracy Requirement.
Comment: The commenter suggests edits to section 95103(k)(6) that clarify that the field accuracy assessment is voluntary…specifically adding the words "if applicable" after the sentence "…and field accuracy assessment". Additionally they suggest adding the words "by other means" to 95103(k)(6)(C). [B 03.05 – WSPA]

Response: ARB agrees with the first part of the comment and has added the "if applicable" language to section 95103(k)(6) as part of the 15-day changes. Instead of adding the language "by other means," ARB staff has further clarified section 95103(k)(6) by including examples of possible options to demonstrate calibration back multiple years in cases where a meter fails calibration. ARB believes these changes address the commenter's concerns.

A-21. Section 95103(k)(6)(A)(1) Approval of Alternative Calibration Methods
Comment: WSPA suggests specific language be added section 95103(k)(6)(A)(1) as follows*:* "If the methods specified in ISO 5167-2 (2003), AGA report No 3 (2003) or 40 CFR §98.7 do not apply or are not possible for a particular device, the procedures in section 95109(b) must be followed to obtain approval for an alternative inspection procedure." [B 03.06 – WSPA]

Response*:* ARB believes this suggested language is not necessary because the alternative procedures in section 95109(b) are already applicable to this section. Section 95109(b) may be used in cases where the ISO or 40 CFR §98.7 method do not apply or are not possible for a particular device.

A-22. Meter Calibration Requirements.
Comment: WSPA recommends specific language be added to section 95103(k)(10) to clarify the requirements for meters or other measurement devices when they represent less than 5% of the total facility emissions. WSPA recommends the following language be inserted in section 95103(k)(10): "When the emissions or product data estimated using the data provided by the device represent less than 5 percent of total facility emissions or product data on an annual basis, the operator must demonstrate to the satisfaction of the verifier or ARB this emission estimate of less than 5 percent of total facility emissions or product data , but there are no requirements to demonstrate accuracy back to the last instance of a successful field accuracy assessment or calibration for these devices." [B 03.07 – WSPA]

Response*:* ARB does not believe the suggested language is necessary, and is not making this change. The proposed change does not take into account situations where multiple meters that make up less than 5 percent of a facility's emissions add up to greater than 5 percent of the total emissions. In cases where multiple meters fail calibration that represent over 5 percent of total emissions, the accuracy of the emissions may be compromised were the changes suggested by the commenter made.

A-23. Aggregation of Stationary Combustion Units at a Facility Providing Power Only Inside the Facility
Comment: Reporter has two locations where stationary combustion sources are used to compress natural gas and provide electric power only inside the facility boundary. These facilities are subject to cap-and-trade obligations for the GHG emissions from sources within each facility. U.S. EPA regulations (40 CFR §98.3) permit all facility emission sources to be grouped for purposes of reporting emissions. Commenter recommends the following

modifications to clarify that such aggregation is permissible under ARB's regulation as well.

"Section 95103(h). Reporting *Starting* 2012. For emissions data reports due in 2012, facility operators may report 2011 emissions using applicable monitoring and calculation methods from 40 CFR Part 98. For entities not required to report 2011 emissions under 40 CFR Part 98, best available data and methods may be used for the 2011 data year. Electric power entities must report 2011 electricity transactions (MWh) and emissions (MT of CO2e) under the full specifications of this article as applicable in 2012. For 2012 reports of 2011 emissions by facilities and suppliers, the missing data substitution requirements specified in this article that are different from the requirements of 40 CFR Part 98 do not apply; missing data for the 2012 report of 2011 emissions must be substituted according to the requirements of 40 CFR Part 98. [Commenter's addition:] *Beginning with emissions data reports due in 2013, facility operators with stationary emission sources included in Section 95112 that do not provide or sell any generated energy outside of the facility boundary may report emissions using applicable monitoring and calculation methods from 40 CFR Part 98*."
[OP 03.10 – PG&E]

Response: These comments and requests are noted by ARB staff. However, since the original proposal did not alter this section, the requested changes are beyond the scope of this rulemaking. Also see Comment and Response to E-2 in section 95115 for additional clarifications.

A-24a. Verification Requirement for Geothermal Facilities
Comment: Proposed language would require geothermal operators emitting > 25,000 MT CO_2e to annually provide third-party verified compliance data despite their being without a compliance obligation. Commenter feels that meeting these new requirements will add significant expenses to these operators, costing each reporting unit tens of thousands of dollars annually, without any corresponding benefits to the environment given that any reasonable alternative to geothermal power generation would significantly increase the emissions produced. Commenter urges staff to modify this proposal to remove verification requirement or return to triennial verification requirements for these operators. [OP 05.01 – GEA]

Response: The verification requirements for geothermal operators were not noticed or modified in the 45-day proposed regulatory change package. Thus, these comments are outside the scope of this regulatory update. However, ARB staff would like to clarify that geothermal facilities that emit 25,000 MTCO_2e or greater are subject to annual third-party verification. These verification requirements are consistent with the treatment of other renewable fuel sources, such as biomass-derived fuels.

A-24b. Verification Requirement for Geothermal Facilities
Comment: Commenter believes that the current proposal for verification increases geothermal energy production costs without corresponding benefit.

Since geothermal does not have a U.S. EPA GHG reporting requirement, and because ARB does not impose a Cap-and-Trade obligation on geothermal, they believe they should be exempted from mandatory reporting. Alternatively, commenter requests to return to triennial verification. [OP 15.01 – CEOC]

Response: See Response to A-24a.

A-24c. Verification Requirement for Geothermal Facilities
Comment: The commenter indicated that geothermal facilities produce renewable energy and are exempted from U.S.EPA greenhouse gas rule, but not ARB's reporting regulation. The verification requirements imposed by ARB increase the cost for a geothermal benefit without a corresponding benefit. CalEnergy requests that the independent verification requirement be removed for geothermal energy production units. [T 02.01 – CEOC]

Response: See Response to A-24a.

§95104 – Emissions Data Report Contents and Mechanism

No comments were received on section 95104.

§95105 – Recordkeeping Requirements

No comments were received on section 95105.

B. Subarticle 2. Electric Power Entities (§95111)

§95111 – Electric Power Entities

B-1a. Contractual Chain and Claims to Asset Controlling Supplier (ACS) Power
Comment: Powerex has expressed concern with the proposed asset controlling supplier provision in Section 95111(a)(5) that would allow a system emission factor intensity assigned to an ACS to be claimed by an importer, "regardless of whether the reporting entity and asset-controlling supplier are adjacent in the market path" on the NERC e-tag. Powerex stated that this provision would relieve any condition that requires title for energy (including the GHG intensity of that energy) to be passed along the contractual chain. Powerex further stated that:

> "ARB should clarify whether or not a contractual chain is required for the importer to be able to claim the intensity of an ACS. As written, an importer is obligated to report the ACS's intensity regardless of whether or not it has contracted with the supplier. In fact, an importer would be able to claim the intensity of an ACS if it had purchased unspecified power on an electronic exchange and had simply scheduled (and e-tagged) the volume during the scheduling process. By effectively

decoupling ACS electricity from the contractual chain, MRR Section 95111(a)(5) has the potential to promote (not impede) resource shuffling via the scheduling process, as schedulers may be selective about which "upstream" schedules they want or don't want. The receipt of a lower than contracted rate via scheduling optimization rather than via contracting is problematic. It also could very well open participants to claims of resource shuffling even though they were optimizing entirely separate parts of their portfolios as a part of the normal activity they conducted before the onset of this program. Powerex therefore calls upon ARB to clarify the relationship between ACS electricity and the contractual chain to ensure that it does not inadvertently promote actual resource shuffling or mistaken claims of resource shuffling." (Powerex) [OP 19.03 – PX]

Response: In 2012, during the reporting process for 2011 emissions data, ARB allowed EPEs to claim the ACS emission factor regardless of whether the contract held was for specified or unspecified power, primarily for GHG inventory purposes. This implementation interpretation was based on language in the "specified source of electricity" definition which indicated that a claim to an ACS emission factor need only be based on the procurement of electricity.

ARB staff notes that discussions with stakeholders regarding the resource shuffling provisions of the cap-and-trade regulation, related to the comments raised by Powerex, are ongoing. At this time, ARB staff is continuing to collect information on this issue and evaluating the ramifications of retaining the existing interpretation or moving toward the suggestions by Powerex of using contracts instead. Given these ongoing discussions, ARB does not believe that changes to the existing language are warranted at this time. However, ARB staff is committed to working with the stakeholders to ensure a successful implementation of this reporting requirement.

B-1b. Contractual Chain and Claims to Asset Controlling Supplier (ACS) Power
Comment: WPTF contends that the proposed provision that would allow an importer to claim ACS power, regardless of contract, is in direct conflict with the cap and trade regulation. WPTF provides additional detail:

"The definition of specified source in the cap and trade regulation states that 'electricity procured from an asset-controlling supplier' is considered a specified source, and further requires that 'the reporting entity must have either full or partial ownership in the facility/unit or a written power contract to procure electricity generated by the facility/unit.' This requirement for ownership or contract is not reflected in the MRR. Further, as a general rule, the reporting regulation does not use NERC tags to assign emissions for imports. Rather, ownership, operational contract and contract rights determine whether power can be specified. ARB has proposed a revision to the definition of 'unspecified power' to clarify that power that is not specified at the time a power transaction is entered into, cannot later be assigned a specified emission rate. WPTF agrees with this provision, but considers that it should apply symmetrically to both high and low emission power. Thus, if an importer purchases 'Schedule C' power from the Intercontinental Exchange (ICE), that power should be assigned the default emission rate, regardless of whether the NERC tag shows the power as originating from a coal facility, or from the system of a low-emission ACS, such as Bonneville Power Administration." [OP 01.01 – WPTF]

With regard to Section 95111 (a)(f) [*sic* which should be 95111(a)(5)] *Imported Electricity Supplied by Asset-Controlling Supplier*, WPTF recommends that these requirements be modified to provide for importing of electricity by either an ACS itself (which would be considered a GPE) or by an entity that holds a specified power contract for ACS-sourced power. This change is necessary to ensure consistency between the MRR and the cap and trade regulation, which requires right of ownership or contract as a condition for claims to specified power. WPTF proposes the following edits:

> *Imported Electricity Supplied by Asset-Controlling Supplier*: The reporting entity must separately report imported electricity supplied by asset-controlling suppliers recognized by ARB <u>when it is the asset controlling supplier or when it has a specified power contract for electricity from an asset controlling supplier's system</u>. The asset controlling supplier must be identified on the NERC e-tags as the PSE at the first point of receipt, regardless of whether the reporting entity and asset-controlling supplier are adjacent in the market path.

<u>Response:</u> With regard to the WPTF statement on assignment of emissions by NERC e-tag and not contract, please see Response to A-15b. The proposed WPTF edits to section 95111(a)(5) are not necessary given the clarifying edits in the 45-day issuance as shown here:

> *Imported Electricity Supplied by Asset-Controlling Suppliers.* The reporting entity must separately report imported electricity supplied by ~~Bonneville Power Administration, an~~ asset-controlling supplier<u>s</u> recognized by ARB. <u>The asset-controlling supplier</u>~~Bonneville Power Administration~~ must be identified on the <u>physical path of</u> NERC e-Tags as the PSE at the first point of receipt~~.~~<u>, regardless of whether the reporting entity and asset-controlling supplier are adjacent in the market path</u>. The reporting entity must:

See also Response to B-1a.

B-2a. <u>Point of Receipt, Point of Delivery, and Source of Generation Definitions</u>
<u>Comment:</u> Powerex states that a clear distinction should be made between the source of generation and the first point of receipt:

> "Several definitions in Section 95102(a) of the MRR that relate to e-tagging (and, in particular, the source and point of receipt for e-tagged electricity) are inconsistent with standards established by the North American Energy Standards Board ("NAESB") and the North American Energy Reliability Corporation ("NERC"). Those standards are used

industry-wide. For ease of implementation, the MRR should be consistent with those standards. In addition, the proposed MRR definitions are internally inconsistent, and potentially conflict with other provisions of the MRR.

"The proposed definition for "Continuous Physical Transmission Path" correctly indicates that "generation source" and "first point of receipt" (or "POR") are two distinct elements on an e-Tag. *See* Section 95102(a)(106) ("'Continuous physical transmission path'" means the full transmission path shown in the physical path table of a single NERC e-tag from *the first point of receipt closest to the generation source* to the final point of delivery closest to the final sink.") (emphasis added). The generation source is indeed different from the POR, so that distinction in the definitions is correct. The source point listed on an e-Tag is a separate and distinct field from the first point of receipt. The former refers to the facility or unit where generation physically takes place. The latter is where a facility or unit delivers its output to the bulk transmission system and could be the same point for numerous facilities or units.

"The distinction is confirmed by both NAESB and NERC definitions. For example, the NERC Reliability Standards define POR as "a location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output." *See* http://www.nerc.com/files/Glossary_of_Terms.pdf.

"However, despite the fact that source and POR are distinct concepts, the proposed definitions for "Source" and "First Point of Receipt" cross-reference each other in a way that misleadingly indicates that the two concepts are the same. Under Section 95102(a)(430), "Source of Generation" states that "imported electricity and wheels are disaggregated by the source on the NERC e-Tag, *also referred to as the first point of receipt*" (emphasis added). And "First Point of Receipt" is defined as "the *generation source* specified on the NERC e-Tag . . . ." (emphasis added). *See* MRR Section 95102(a)(176). To avoid conflating the two distinct definitions, Powerex recommends that these cross-references be modified to read as follows:

> (176) "First point of receipt" <u>means the location from which a Generator delivers its output to the transmission system (the closest POR to the generation source)</u> ~~the generation source specified on the NERC e-Tag~~, where defined points have been established through the NERC Registry. When NERC e-Tags are not used to document electricity deliveries, as may be the case within a balancing authority, the first point of receipt is the location of the individual generating facility or unit, or group of generating facilities or units. Imported electricity and wheeled electricity are disaggregated by the first point of receipt on the NERC e-Tag.

(430) “Source of generation” or “generation source” means the generation source identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Imported electricity and wheels are disaggregated by the source on the NERC e- Tag~~, also referred to as the first point of receipt~~.
[OP 19.01 – PX], [OP 19.02 - PX]

Response: The terms “first point of receipt” and “final point of delivery” are used throughout the requirements for electric power entities, including in sections 95102, 95105, and 95111 and are defined for purposes of the MRR to be synonymous with source and sink, respectively, as shown in the NERC e-Tag graphic below. ARB believes the proposed regulatory amendments are clear and necessary to identify the location of the source/first point of receipt and sink/final point of delivery. As such, ARB declines to make the suggested changes at this time.

Physical Path							
CA	TP	PSE	POR	POD	Sched Entities	Contract	Misc
CA 1		PSE 1	ARB Defined Source and First Point of Receipt				
	TP 1	PSE 1	POR A	POD A	SE 1		
	TP 2	PSE 1	POR B (same as POD A)	POD B	SE2		
	TP 2	PSE 2	POR C (same as POD B)	POD C	SE2		
	TP 3	PSE 3	POR D (same as POD C)	POD D	SE3		
CA 2		PSE 3	ARB Defined Sink and Final Point of Delivery				

CA: Control Area
TP: Transmission Provider
PSE: Purchasing Selling Entity
POR: Point of Receipt
POD: Point of Delivery

B-2b. Point of Receipt, Point of Delivery, and Source of Generation Definitions
Comment: This comment pertains to the point of delivery for exports. SCE contends that, to calculate electricity exports, ARB should use as a reference point the first point of delivery outside of California rather than the final point of delivery outside of California. SCE states that distinguishing between the “final” and “first” point of delivery in California is crucial because exporters cannot know with any certainty where the final point of delivery will be for the electricity they sell. SCE recommends that the last sentence of the new final point of delivery definition be deleted: “Exported electricity is disaggregated by the final point of delivery on the NERC e-tag” from the definition.
[OP 08.05 – SCE]

Response: SCE contends that the proposed change is necessary in order to facilitate the use of “multiple-tag wheel” transactions and qualified export (QE) adjustment claims. The current reporting regulation design is predicated on electricity transaction documentation based on single e-tags, where EPEs will have clear knowledge of the final point of delivery on the NERC e-tag. Multiple-tag transactions will be viewed by ARB staff in their single-tag component parts which is consistent with the design feature that also applies to exchange agreements set forth in section 95111(a)(7) in which the import and export segments of exchange agreements must be reported separately. In addition, SCE ties its proposed change on the “final point of delivery” definition to its larger proposal on qualified exports, which ARB does not accept, as addressed in Response to B-9a.

B-2c. Point of Receipt, Point of Delivery, and Source of Generation Definitions
Comment: SCE states that the transmission loss factors in Section 95111(b) that refer to the “first point of receipt in California” specifically refer to the first point at which electricity is brought into California. However, SCE contends that a discrepancy is created with the proposed new definition for “first point of receipt” that references the point closest to the generation source even though this point may be located outside of California. For clarity, SCE recommends that the relevant portions of Section 95111(b) should be changed to read “first point of delivery [not ‘receipt’] in California.”
[OP 08.04 – SCE]

Response: ARB believes the existing qualifying phrase “in California” is sufficient to distinguish a California point on the grid from an out-of-state point. As such, ARB declines to make the requested change.

B-2d. Point of Receipt, Point of Delivery, and Source of Generation Definitions
Comment: WPTF recommends addition of a new definition for ‘First Point of delivery outside California’ (as shown below) to ensure equivalent treatment of wheel-throughs and qualified exports. [OP 01.07 – WPTF]

> *(175) “First point of delivery outside California means the first defined point on the transmission system located inside California at which exported electricity and electricity wheeled through California may be measured, consistent with defined points that have been established through the NERC registry.*

Similarly, WPTF recommends that this provision be modified for consistent treatment of exports and wheeled-through power as shown below.

> *Exported Electricity* The electric power entity must report exported electricity in MWh and associated GHG emissions in MT of CO_2e for unspecified sources disaggregated by each ~~final~~ first point of delivery outside the state of California and for each specified source disaggregated by each ~~final~~ first point of delivery outside the state of California, as well as the following information:

[OP 01.07 – WPTF]

Response: ARB believes the requirements are clear, and that distinguishing between electricity wheeled through California and qualified exports is necessary to properly account for GHG emissions from all imported electricity and all electricity generated in the state of California. As specified in the regulation, only wheeled electricity is accepted by ARB as not sinking in California, due to the single NERC e-Tag documenting the sink as located outside California. The qualified export adjustment is provided as a compliance reduction in the cap-and-trade regulation pursuant to section 95852(b). Based on this, ARB declines to make the requested changes.

B-3a. Asset Controlling Supplier Post-Verification Status

Comment: In Section 95111(f)(5), ARB issued proposed language in which asset-controlling suppliers would lose their designation if they receive an adverse verification statement, but may reapply in the following year for re-designation. SCPPA expressed concern with this provision and considers it ambiguous because it is unclear whether the effect of such a loss of designation would be prospective-only, or both retrospective and prospective. SCPPA states:

> "The possibility that revocation [of ACS status] would have a retroactive effect would make it difficult for an importer that purchases from an Asset Controlling Supplier to estimate the number of allowances that it will need to satisfy its cap-and-trade compliance obligation. The importer would have to take into account the possibility that revocation of the Asset Controlling Supplier's status as being an Asset Controlling Supplier would retroactively cause the emission factor associated with imports to be the default emission factor rather than the lower emission factor that was specific to the Asset Controlling Supplier. Uncertainty about the security of the Asset Controlling Supplier's emission factor could cause the downstream importer to purchase more allowances than necessary, putting unnecessary pressure on allowance prices in the market for cap-and-trade allowances." (SCPPA)

SCPPA proposes that in order to assure that revocation of ACS status would not have a retroactive effect on emission factors associated with purchases from an ACS, the following sentence should be added to section 95111(f)(5): "The loss of designation as being an Asset Controlling Supplier will not have a retroactive effect on the emission factor associated with purchases of electricity from the affected Asset-Controlling Supplier." [OP 06.02 – SCPPA]

Response: Under the amendments in the 45-day and 15-day packages, ARB has clarified that ACS system emission factors are calculated on a two-year lag and are subject to verification prior to public issuance by ARB. For example, an ACS system emission factor for calendar year 2013 would be based on 2011 emissions data reported by June 1, 2012 and verified by September 1, 2012. In the first year of implementation for this amended requirement, ACS system emission factors will likely be issued by the end of 2012 for use in calendar year 2013. A loss of designation for 2013 would only occur if an ACS did not successfully complete the reporting and verification process in 2012. Market participants can safely avoid the risk that a loss of designation would impose by not contracting for ACS power in 2013 prior to the issuance of the system emission factors by ARB. Thus, a loss of designation would be prospective only, as ACS status would not be revoked retroactively.

Accordingly, ARB believes that the amendments as proposed are sufficient to address the commenters' concerns, given these additional clarifications. These amendments will not result in retroactive loss of ACS system emission factors. A loss of designation would be prospective only. EPEs may protect themselves from prospective issues by waiting to contract until after the ACS factors are published by ARB.

B-3b. Asset Controlling Supplier Post-Verification Status

Comment: LADWP assumes a loss of ACS designation would apply retroactively and negatively impact market participants. LADWP states: "In the event an ACS receives an adverse verification opinion on their annual report, revoking the ACS status would adversely affect the downstream purchasers of the electricity and the GHG emission allowance market as a whole. To resolve this, LADWP would simply delete the proposed 'loss of designation' sentence: *Asset-controlling suppliers will also lose their designation if they receive an adverse verification statement, but may reapply in the following year for re-designation*. In the event an ACS received an adverse verification statement, LADWP recommends that an ACS be treated the same as other reporting entities where ARB would develop an assigned emissions level for the reporting entity in accordance with 95103(g)."

LADWP notes that in the absence of such an approach the emission factor used by the downstream purchasers of the electricity could increase dramatically in the subsequent reporting year if ACS status is revoked. For example, if Bonneville Power Administration lost their ACS status, the emission factor used by the downstream purchasers would increase from 0.086 to 0.428, a difference of 0.342 metric tons CO_2e per MWh which is nearly a 400% increase. Depending on the quantity of electricity purchased, this could amount to a significant increase in the downstream purchaser's cap-and-trade compliance obligation, which could require the purchase of additional emission allowances from the market. This additional demand for allowances will tighten the supply of allowances, thereby causing the price of the emissions allowances to increase and affect all the market participants. Therefore, LADWP recommends deleting the last sentence the last paragraph in 95111(f)(5): Asset-controlling suppliers will also lose their designation if they receive an adverse verification statement, but may reapply in the following year for re-designation. [OP 17.04 – LADWP]

Response: With regard to the LADWP recommendation regarding an assigned emission level (AEL) approach, ARB believes this works well for specified sources because representative data is reported to U.S. EPA and/or U.S. Energy Information Administration (EIA). However, in contrast, there are no similar reporting requirements for asset controlling suppliers, and while the component parts of the ACS fleet may be reported to U.S. EPA or U.S. EIA, considerable uncertainty would remain regarding the number and level of specified and unspecified purchases and sales associated with the ACS system. This uncertainty would seriously compromise the potential accuracy of an AEL for an asset controlling supplier, which does not make it a viable option. Moreover, as noted in Response to B-3a, ARB believes it is clear that a loss of ACS designation cannot be made retroactively. For these reasons, the change requested by LADWP was not made.

B-4. Publication of Asset Controlling Supplier Emission Factors

Comment: Section 95111(b)(3) states that "ARB will calculate and publish on the ARB Mandatory Reporting website the system emission factors for all asset-controlling suppliers." SCE proposes that the system emission factor for each asset-controlling supplier should be published no less than ninety days prior to the year for which the system emission factors would apply. This would establish a close of business publication date of October 2. [OP 08.01 – SCE]

Response: ARB understands that electric power entities would like to obtain asset-controlling supplier system emission factor values as far in advance of the year in which the system emission factors would apply in order to transact on this information. During this first year, some flexibility was granted. However, in the future, asset-controlling supplier applications and system emission factor calculations are due by June 1 and must be verified by September 1. ARB commits to publishing system emission factors in a timely manner after the verification process is complete.

B-5. Electricity Wheeled Through California

Comment: LADWP states that 95111(a)(8), Electricity Wheeled through California, is unclear as currently written. LADWP explained that during verification of the 2011 electric power entity reports, the question arose as to which entity is responsible for reporting electricity wheeled through California, the entity that owns the electricity (the purchasing/selling entity) or the transmission provider? ARB staff provided guidance that the purchasing/selling entity is responsible for reporting electricity wheeled through California, citing related language in section 95105(d)(5). LADWP recommends that section 95111(a)(8) be amended (as shown below) to specify the entity responsible for reporting these transactions is the is the purchasing/selling entity on the physical path of the NERC e-tag.

> (8) *Electricity Wheeled Through California*. The electric power entity who is the PSE on the physical path of the NERC e-tag must separately report electricity wheeled through California, aggregated by first point of receipt outside California, and must exclude wheeled power transactions from reported imports and exports. When reporting electricity wheeled through California, the power entity must include the quantities of electricity wheeled through California as measured at the first point of delivery inside the state of California.

[OP 17.03 – LADWP]

Response: ARB agrees that the proposed amendment to 95111(a)(8) is consistent with language in 95105(d)(5), and also with other provisions in the regulation specified for imports and exports. ARB has modified the language in the 15-day changes to address the stakeholder's concerns.

B-6a. Ensuring Completeness of Reporting from Electric Power Entities

Comment: SCE urges ARB to develop a plan for enforcing the mandatory reporting of emissions, particular for importers that transact at out-of-state interties. SCE states that it has serious concerns about gaps in emissions reporting from first deliverers of electricity, and the potential effects on both GHG and electricity markets. For example, out-of-state entities could simply choose not to report emissions associated with sales into the California Independent Systems Operator ("CAISO") territory at out-of-state interties, under the pretext that the ARB does not have jurisdiction over these sales (and correspondingly, the emissions associated with these sales). SCE contends that in the event ARB cannot determine whether there are missing emissions from its reports, or if the ARB is unable to fully assert its jurisdiction over such sellers, there would likely be damaging effects on the GHG and electricity markets.

SCE proposes two concrete steps for the ARB to address these concerns. First, the ARB should initiate a process for collecting the data needed to identify all electricity imports into California. This data must include all NERC e-Tags created when electricity is scheduled into California. SCE is encouraged that ARB appears to be seeking e-tag data from the CAISO, but reviewing only those e-tags where the CAISO is listed as the PSE is neither comprehensive nor sufficient. SCE notes that, as of August 1, 2012, the CAISO will no longer approve any e-Tags if the CAISO is listed in them as the PSE. Therefore, the data that the ARB will obtain from the CAISO will be irrelevant in verifying that all electricity imports are accounted for after cap-and-trade program compliance begins. Instead, in order to verify that all electricity imports are accounted for, the ARB must independently obtain e-tag data for all e-tags that were created to document the electricity imports into any of the California balancing area authorities, regardless of who is the PSE.

Second, the ARB must develop a process for enforcing compliance on those entities that do not report their emissions. The ARB should formally outline its regulatory and statutory authority to enforce compliance, as well as the enforcement actions it will take and the consequences for non-compliance. SCE urges the ARB to adopt these steps in order to prevent foreseeable inefficiencies in emissions and electricity markets. SCE raised these concerns in written in 45-day comments and verbally at the September 20, 2012 Board Meeting. [OP 08.06 – SCE], [T 03.01 - SCE]

Response: ARB appreciates the commenter's suggestions. All EPEs subject to the reporting regulation are subject to ARB's enforcement provisions, and ARB will take appropriate action to ensure that all of these entities are following the requirements of the regulation. ARB has begun work on a process for collecting the data needed to identify all electricity imports into California. ARB intends to obtain annual state-wide values for each transaction type (imports, exports, and wheels) from Open Access Technology International, Inc. (OATI), which can be compared with reported emissions to provide a high level overview of reported emissions vs. total emissions. ARB will also obtain annual state-wide values from OATI for each EPE by transaction type to determine the level of reporting among EPEs. Raw e-tag data will be used to verify the summary data.

This data will serve as an additional check to allow ARB to verify that all entities that have imported, exported, or wheeled electricity have, or have not, reported under the reporting regulation. As noted by WPTF, the recent subpoena of the California Independent System Operator (CAISO) does not address this concern because the data request was limited to transactions for which the CAISO was listed as the purchasing-selling entity (PSE) on the NERC tags.

B-6b. Ensuring Completeness of Reporting from Electric Power Entities
Comment: WPTF remains concerned about ARB's ability to verify that all importers of electricity have reported under the reporting regulation. Without a mechanism for independent verification, an importer of electricity that does not participate in the cap-and-trade program will not be detected by ARB, and will incur a significant cost advantage in the wholesale electricity markets. While third-party verification will help ensure accuracy of reported information, it will not assist ARB in determining whether all importers of electricity have reported. As a result, electric power entities could avoid obligations under the cap-and-trade program by simply not reporting. The recent subpoena of the California Independent System Operator does not address this concern because the data request was limited to imports for which the CAISO was listed as the purchasing-selling entity on the NERC tags.

WPTF has previously suggested that ARB contract with OATI to provide independent data on the quantity of imports to California and the entity responsible for each import. If this is not possible due to OATI confidentiality restrictions, then ARB should collect this data annually from the California Independent System Operator and other California balancing area authorities. [OP 01.05 – WPTF]

Response: See Response to B-6a.

B-7. Implement Regional Default Emission Factors for Electricity Imports
Comment: TransAlta "encourages ARB to implement regional default emission averages [factors] for electricity imports." TransAlta contends that this would render all generators equal and respect each state's own methods of transitioning to cleaner sources of energy. On the issue of transitioning to cleaner sources of energy, TransAlta does not provide any further detail or discussion. [OP 02.02 – TA], [OP 10.02 - TA]

Response: No modifications related to the default emission factor were proposed in this rulemaking, and the comment is therefore outside the scope of this rulemaking. However, ARB staff will continue to monitor electricity flows in the Western Electricity Coordinating Council (WECC) area and evaluate the appropriateness of the single default emission factor for unspecified power coming into California.

B-8. Electric Power Entity Status

Comment: APS contends that there is a lack of clarity in the regulations regarding the process by which electric power entities determine their emissions reporting status among the following options: unspecified source of electricity, generation providing entity, and asset controlling supplier. [OP 12.02 – APS, T 06.02 – APS]

Response: ARB has described the process by which EPEs will be recognized as generation providing entities in the GPE section of this report (see Response to A-8a). Also, as shown in Responses to A-3a, A-3b, B-1a, B-3a, and B-3b, ARB staff has provided further clarification on the requirements for asset controlling suppliers. In addition, ARB staff clarified the definition of unspecified source in the 45-day language which was well supported by stakeholders (see Response to A-15a). Overall, ARB staff believes the clarifications to the generation providing entity designation address APS' concerns.

B-9a. Qualified Exports (QE)

Comment: WPTF believes that there are two significant problems with the current QE related requirements. First, the rule that only allows netting of electricity exports that occur simultaneous to an import may significantly overestimate state-wide net imports, and as a result, will increase program costs due to the additional demand for allowances this creates. Second, the requirement that quantified exports are assigned the lowest-emission rate of imports occurring in that hour could yield the unexpected result that importers of renewable energy incur a higher carbon compliance obligation than importers of fossil generation.

In support of its first point, WPTF describes a survey of its members [the results of which] suggest that the quantity of 'residual' exports [that are not qualified exports] under current program rules – i.e. those exports that cannot be netted due to the requirement that qualified exports be netted against simultaneous imports – may be as much as 70% of total exports, with the value ranging from 28% to 100% among individual WPTF members. WPTF then extrapolates this into a system wide estimate of how CARB's approach to qualified exports for 2011 may over-state California load by three percent, which WPTF then converts to ton and dollar values. WPTF did not provide any additional information on the survey methodology or results. In support of its second point, WPTF offers sample QE calculations.

In addition, WPTF recommends that CARB analyze the emission reports of qualified exports to determine the extent to which the approach overstates net electricity imports. WPTF asks ARB to work with the California balancing area authorities to compare the total volume of imports subject to the program to California-wide net interchange. If the difference between these numbers is significant, as we suspect it will be, ARB should revise the regulation to allow for netting of all electricity exports.

Finally, WPTF contends that there is “disparate treatment of single and dual tag wheel-throughs” that is arbitrary and unfair for electric power entities, that it creates an incentive for use of single-tag wheel-throughs over dual tags, and that this incentive will reduce efficiency, because the dual tag import-export schedule gives the CAISO more flexibility in balancing its system than the single tag schedules. [OP 01.06 - WPTF]

Response: In its comments, WPTF noted that “the rule for assigning emissions to qualified exports is set out in the cap and trade regulation rather than the MRR. Therefore, we recommend that this issue be reconsidered in both the MRR and cap and trade rule-makings next year." ARB staff agrees with WPTF that the QE issue is out of scope of this regulatory update process and notes that the amendments to the cap-and-trade regulation made in this rulemaking are limited to the definitions section only, and only to those definitions which correspond to those reporting regulation definitions modified in this rulemaking. To the extent the comment raises other cap-and-trade related issues, those are also outside the scope of this rulemaking and not addressed in this response. With regards to treatment of single and dual tag wheel-throughs, please see Response to B-2b.

B-9b. Qualified Exports (QE)
Comment: APS stated as its “Concern #1”:

“Electricity purchases from and sales to the CAISO have unknown points of origin and consumption, respectively. However, it is known that instances exist where electricity generators outside the state of California produce power that is sold to the CAISO at the same time that electricity providers serve load outside the state of California using power purchased from the CAISO … The CAISO operates the bulk of California’s power grid and wholesale electric markets. It does so without ever taking ownership of the power, which means that electric entities, whether within or outside the state, that deliver power to a CAISO delivery point located within the state of California are the ones that will have a GHG emission compliance obligation beginning in 2013.

In CARB’s October 2011 Final Statement of Reasons to California’s Cap-and-Trade Program, CARB acknowledges that a provision ‘is necessary to address stakeholder concerns regarding ‘simultaneous exchanges’ and recognizes that this kind of exchange is similar to the wheeling of electricity through California, in that not all of the electricity being imported is actually used to serve California load.’ Thus, the qualified export (“QE”) definition was modified to better resolve concerns regarding the wheel-through-like scenario. Unfortunately, this modification did not go far enough to address the blind wheel-through situations that sometimes occur with CAISO transactions. When energy is delivered to the CAISO, the final point of delivery is unknown, and because electricity is fungible, in reality it ends up at several different locations, some of which are outside the state of California. For example, APS serves a portion of its load, which is located on the Arizona side of the California-Arizona border in Ehrenberg, with power purchased from the CAISO. Similarly, Valley Electric Association, Inc. ("VEA" is an electricity service provider whose service territory is primarily located in Nevada) will be joining the CAISO in 2013. Both APS‟s Ehrenberg load and VEA‟s service territory are examples of load that is serviced through the CAISO but is located outside of the state of California.

At the same time, power that is purchased from the CAISO does not identify the original source of that power. And again, because power is fungible, it most likely is generated from many sources, some of which are not located within the state of California. Case in point, APS sells power into the CAISO from generating sources that are located in Arizona and New Mexico. Therefore, there is nearly always a portion of the electricity that is generated outside of the state of California that is serving load outside the state of California, but is transacted through CAISO. Regulating these transactions falls outside of CARB‟s jurisdictional territory.

PROPOSED RECOMMENDATION: The QE allows for imports and exports that occur *simultaneously* to be netted within the same hour. Unfortunately, only allowing for intra-hour netting does not properly address the problem that "not all of the electricity being imported is actually used to serve California load." Another challenge is that transactions with the CAISO are blind and, therefore, it is unknown where power originates or is consumed. Furthermore, the calculation methodology does not fairly quantify netted emissions.

Therefore, APS recommends that the following changes be made to the regulatory language:

§ 95802 (225) "Qualified Export" means electricity that is exported in the same hour calendar year as imported electricity and documented by NERC E-tags. When imports are not documented on NERC E-tags, because a facility or unit located outside the state of California has a first point of interconnection with a California balancing authority area, the reporting entity may demonstrate hourly annual electricity delivery consistent with the record keeping requirements of the California balancing authority area, including records of revenue quality meter data, invoices, or settlements data. Only electricity exported within the same hour calendar year and by the same importer as the imported electricity is a qualified export. It is not necessary for the imported and exported electricity (as defined in the MRR) to enter or leave California at the same intertie. Qualified exports shall not result in a negative compliance obligation for any hour calendar year.

§ 95852(b)(5) QE adjustment. An adjustment to the compliance obligation pursuant to the calculation in 95852(b)(1) may be made for exported and imported electricity during the same hour calendar year by the same PSE. Emissions included in the QE adjustment for qualified exports claimed by a first deliverer must meet the following requirements:

(A) During any hour calendar year in which an electricity importer claims qualified exports and corresponding imports, the maximum amount of QE adjustment for the hour calendar year shall be calculated as not exceed the product of:
1. The lower of either the quantity of exports or imports (MWh) for the hour calendar year; multiplied by
2. The lowest weighted average of the emissions factors for of any portion of the qualified imports; minus
3. The quantity of imports (MWh) for the calendar year; multiplied by
4. The weighted average of the emissions factors for the qualified exports;
5. With zero being the maximum QE adjustment.
Additionally, APS recommends that the following be added in order to prevent market manipulation: 'Establishment of a strawman for the primary purpose of maximizing an EPE‟s QE adjustment is prohibited.'"
[OP 12.01 – APS], [T 06.01 – APS]

Response: Regarding the commenter's suggestions related to qualified exports, ARB notes that the amendments to the cap-and-trade regulation made in this rulemaking are limited to the definitions section only, and only to those definitions which correspond to those reporting regulation definitions modified in this rulemaking. Since the definition of "qualified export" was not modified, APS' comments are outside the scope of this rulemaking. To the extent the comment raises other cap-and-trade related issues, those are also outside the scope of this rulemaking and not addressed in this response. See also Response to B-9a. Regarding APS' comments about transactions falling outside of California's jurisdiction, see Response to A-5b.

B-9c. Qualified Exports (QE)

Comment: SCE states that ARB should amend its designation of imported and exported electricity to allow for the efficient use of the qualified exports adjustment. SCE offers two proposed changes. First, to calculate electricity exports, ARB should reference the 'first point of delivery outside of California' rather than the 'final point of delivery outside of California.' Second, to calculate electricity imports, ARB should consider electricity with a point of receipt outside of California in addition to electricity generated outside of California.

In support of its first proposed change, SCE states that this change is crucial because exporters cannot know with any certainty where the final point of delivery will be for the electricity they sell, and without such clarification an entity may, for example, sell electricity at an out-of-state intertie and bring a concurrent import into the state with the intent to form a multiple-tag wheel and claim the QE Adjustment. In support of its second change, SCE states that ARB should consider any electricity brought into California from a point of receipt outside of California as an import, regardless of where that electricity was generated. [OP 08.03 – SCE]

Response: See Response to B-9a.

B-10. Resource Shuffling

Comment: TransAlta contends that Coal Transition Power from its Centralia generation plant should be exempt from accusations of resource shuffling, for the reason that it has "reached an historic collaborative agreement with environmental organizations, legislators and labor groups to transition away from coal [at TransAlta's] 1340 MW generating station in Centralia Washington, effectively ending coal power in the state by 2025." [OP 02.01 - TA]

APS states that there is a lack of clarity in the regulations regarding the types of conduct or transactions that would trigger a finding of resource shuffling, and offers recommendations on this issue. Powerex, SCE, and WPTF respectively state that ARB should also address the issue of resource shuffling. [OP 12.03 - APS]

Response: The issue of resource shuffling is primarily a cap and trade issue and is outside the scope of the modifications proposed in this rulemaking.

B-11. Generation Meter Data Retention and Verification for Specified Imported Electricity

Comment: The commenter recommends that generation meter data be retained for documentation and to enable verification to ensure actual facility generation matches the e-tag. This change is necessary to ensure that the regulation does not lead to the unintended consequence of over-accounting of low-emission generation. More specifically, WPTF is concerned that ARB's reliance on a combination of contracts and NERC tags to document direct delivery of low-emission power could result in over-counting of renewable imports specifically, and low-emission imports more generally. For instance, if an importer schedules 100 MW from a Northwest wind generator into CA, but in real-time the generator only generates 50 MWs, then the control area would firm the schedule with system power. In this case, the NERC e-tag would show 100 MW of wind generation, but in reality only 50 MWs of zero emission power flowed. While the RPS program would allow only 50 MW to be credited toward 'category one imports', under the current MRR rules, 100 MW would be attributed a zero emission rate.

(1) *Registration Information of Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment.* The following information is required:

(A) …

(N) Retain for verification generation meter data to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered; [OP 01.04 – WPTF]

Response: ARB staff agrees with the comment. The text has been modified in the 15-day proposal. The change is consistent with ARB staff's intention that the electricity generated by the specified facility must demonstrate generation and transmission into California. Retention and verification of generation meter data for specified imported electricity is consistent with the delivery tracking conditions required in section 95131(b)(6).

B-12. Demonstrating Compliance with MRR Section 95111(b)(5) for Renewable Portfolio Standard (RPS) Adjustment Eligibility

Comment: The commenter commends ARB for requiring entities in section 95111(g)(1)(M) to report to the ARB when RECs have been reported as an RPS Adjustment and whether they have been placed in a Western Renewable Energy Generation Information System ("WREGIS") retirement subaccount. SCE states that it is crucial for the ARB to be able to tell whether a Renewable Energy Credit (REC) has been placed in an entity's retirement subaccount to ensure that the electricity is being used for RPS compliance in California. SCE also recommends that the ARB amend the cap-and-trade regulation to specify that RECs must be held in a retirement subaccount and consequently retired for California RPS compliance in order to claim the RPS Adjustment for imports of specified renewable electricity. Otherwise, one compliance entity might claim an RPS Adjustment tied to a specific REC, then sell the REC to a buyer that also claims the RPS Adjustment. This addition to the cap-and-trade regulation will eliminate the potential for double-counting of the zero emissions attributed to out-of-state renewable electricity in the event a REC is sold. [OP 08.02 – SCE]

Response: ARB staff agrees with the portion of the comment regarding the reporting of RECs from the commenter and believes the proposed regulation implements this intention. Section 95111(b)(5) of the reporting regulation requires reporting entities who choose to take the RPS adjustment to comply with section 95852(b)(4) of the cap-and-trade regulation. Section 95852(b)(4) of the cap-and-trade regulation states "RECs associated with the electricity claimed for the RPS adjustment must be used to comply with California RPS requirements during the same year in which the RPS adjustment is claimed." ARB staff is implementing this requirement by requiring retention and verification of documentation that the RECs associated with eligible RPS adjustments have been placed in a retirement subaccount and designated as retired for the purpose of compliance with the California RPS program. This approach to implementation ensures one compliance entity does not claim an RPS Adjustment tied to a specific REC, then sell the REC to a buyer that does not use the REC for compliance with the California RPS program or also claims the RPS Adjustment. This is necessary to fulfill the intention of the adjustment to the compliance obligation and eliminate the potential for double-counting in the event a REC is sold. To implement this provision of the cap-and-trade regulation, the MRR proposal includes the tracking requirements below.

Proposed section 95111(g)(1)(M) requires reporting the serial numbers of Renewable Energy Credits (RECs) for purposes of the RPS adjustment as specified below:

1. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment as well as whether the

RECs have been placed in a retirement subaccount and designated as retired for the purpose of compliance with the California RPS program.

2. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment in a previous emissions data report year that later were withdrawn from the retirement subaccount, the associated emissions data report year the RPS adjustment was claimed, and date of REC withdrawal.

Finally, this response does not address the portions of the comment focused on suggested future cap-and-trade regulatory amendments which are outside the scope of this rulemaking.

B-13a. ARB Should not Require RECs to be Placed in a Retirement Subaccount to be Eligible for the RPS Adjustment

Comment: RECs must be able to serve both an entity's [ARB] GHG compliance obligations and its [CEC/CPUC] RPS compliance obligations. In section 95111(g)(1)(M), it is vital that the phrase "whether the RECs have been placed in a retirement subaccount" be interpreted quite literally. That is, it must refer to the report of the status of the RECs (whether or not they have been placed in a retirement subaccount) used for claiming the RPS adjustment, rather than establishing a requirement that the RECs be placed in such a subaccount as a condition of claiming the RPS adjustment.
In most instances for retail providers who are also Electric Service Providers, like Noble Solutions, a REC is retired in the year it is claimed for RPS purposes irrespective of the year in which the REC was created. For GHG reporting purposes, a REC needs to be reported in the year of its creation, but does not need to be retired in the year it is reported. It is essential that the rules promulgated by ARB and the CPUC be in harmony, to insure that the complementary policies of GHG management and RPS development can be met. [OP 04.01 – NA]

Noble Solutions states that the GHG Reporting Tool, as currently designed, does not accommodate Noble's interpretation of Section 95111(g)(1)(M). Specifically, certain cells do not permit the reporting of RECs for purposes of claiming the RPS adjustment without identifying the RECs as being retired in a WREGIS retirement subaccount. The Reporting Tool must be modified to accommodate the reporting of RECs for purposes of claiming the RPS adjustment, without requiring identification of the RECs as being retired in WREGIS. [OP 04.02 - NA]

Response: ARB respectfully disagrees with the commenters for reasons stated in Response to B-12: The approach to implementation ensures one compliance entity does not claim an RPS Adjustment tied to a specific REC, then sell the REC to a buyer that does not use the REC for compliance with the California RPS program or also claims the RPS Adjustment. This is necessary to fulfill the intention of the adjustment to the compliance obligation and eliminate the potential for double-counting in the event a REC is sold. For the RPS adjustment, ARB does not require RECs to be reported and retired in the year of generation (creation). Instead, ARB allows an adjustment to the compliance obligation in the year the REC is retired. ARB will modify the reporting tool to conform to the adopted requirements.

B-13b. ARB Should not Require RECs to be Placed in a Retirement Subaccount to be Eligible for the RPS Adjustment

Comment: ARB should clarify that reporting of a REC's status as 'non-retired' will not preclude use of the RPS adjustment and modify the reporting worksheet accordingly. WPTF proposed the following edits as shown below. [OP01.03 – WPTF]

> *Imported Electricity from Specified Facilities or Units.* The electric power entity must report all direct delivery of electricity as from a specified source for facilities or units in which they are a generation providing entity (GPE) or for which they have a specified power contract. ~~have a written power contract to procure electricity~~. When reporting imported electricity from specified facilities or units, the electric power entity must disaggregate electricity deliveries and associated GHG emissions by facility or unit and by first point of receipt, as applicable. The reporting entity must also report total GHG emissions and MWh from specified sources and the sum of emissions from specified sources explicitly listed as not covered pursuant to section 95852.2 of the cap-and-trade regulation.
>
> …
>
> 3. Provide the serial numbers RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment as well as whether the RECs have been placed in a retirement subaccount and designated as retired for the purpose of compliance with the California RPS program.
>
> 2. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment in a previous emissions data report year that later were withdrawn from the retirement subaccount, the associated emissions data report year the RPS adjustment was claimed, and date of REC withdrawal.
>
> 3. RECs associated with electricity generated, directly delivered, and reported as specified imported electricity and whether or not the RECs have been placed in a retirement subaccount.

Response: See Response to B-13a.

B-13c. ARB Should not Require RECs to be Placed in a Retirement Subaccount to be Eligible for the RPS Adjustment

Comment: Clarify that the renewable energy credit ("REC") reporting provisions in section 95111(g)(1)(M) are not intended to prevent an importer of electricity from claiming an RPS adjustment before retiring the associated RECs. [OP 06.01 – SCPPA]

Response: See Response to B-13a.

B-13d. ARB Should not Require RECs to be Placed in a Retirement Subaccount to be Eligible for the RPS Adjustment

Comment: The proposed amendment does not show the link between this new requirement to report REC serial numbers and satisfying the REC retirement requirement in the cap-and-trade regulation. This is an important connection that needs to be stated explicitly in the rule, so that reporting entities will know that reporting of REC serial numbers pursuant to section 95111(g)(1(M) satisfies the REC retirement requirements in the cap-and-trade regulation section 95852(b)(4)—the RPS adjustment. In addition, REC reporting requirements in the MRR need to be flexible to allow for adjustments made to the RECs used for the RPS report. The RPS and Power Disclosure report is submitted to CEC on June 1 but not finalized until October 1. During that period, adjustments may be made to the RECs used for the RPS report as a result of the CEC audit. Therefore, the REC reporting requirements in section 95111(g)(1(M) of the MRR need to be flexible to allow for adjustments made to the RECs used for RPS compliance. Specifically, LADWP recommends the following changes:

(1) *Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment.* The following information is required:

(A) The facility names and, for specification to the unit level, the facility and unit names.

***

(M) To satisfy the REC retirement requirements in sections 95852(b)(3) and 95852(b)(4) of the cap-and-trade regulation, ~~P~~provide the primary facility name, total number~~, serial numbers~~ of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the RECs as specified below:

1. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment as well as whether the RECs:

a) H~~h~~ave been placed in a retirement subaccount and designated as retired for the purpose of compliance with the California RPS program.

b) Will eventually be placed in a retirement subaccount and be designated as retired for the purpose of compliance with the California RPS program.

2. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment in a previous emissions data report year that ~~later~~ were later withdrawn from the retirement subaccount or modified, the associated emissions data report year the RPS adjustment was claimed, and the date of REC withdrawal or modification.

3. RECs associated with electricity generated, directly delivered, and reported as specified imported electricity and whether or not the RECs have been or would later be placed in a retirement subaccount.

[OP 17.05a – LADWP]

Response: See Response to B-13a.

B-13e. ARB Should not Require RECs to be Placed in a Retirement Subaccount to be Eligible for the RPS Adjustment

Comment: The commenter would like clarification that the provisions about reporting of renewable energy credits are not intended to prevent an importer of electricity from claiming an RPS adjustment before retiring the associated credits. [T 05.02 – SCPPA]

Response: ARB believes the requirements are clear. ARB respectfully disagrees with the commenters for reasons stated in Response to B-12: The approach to implementation ensures one compliance entity does not claim an RPS Adjustment tied to a specific REC, and then sell the REC to a buyer that does not use the REC for compliance with the California RPS program or also claims the RPS Adjustment. This is necessary to fulfill the intention of the adjustment to the compliance obligation and eliminate the potential for double-counting in the event a REC is sold. For the RPS adjustment, ARB does not require RECs to be reported and retired in the year of generation (creation). Instead, ARB allows an adjustment to the compliance obligation in the year the REC is retired. ARB will modify the reporting tool to conform to the adopted requirements.

B-14a. Reporting REC Serial Numbers for Specified Imported Electricity

Comment: This is an important connection that needs to be stated explicitly in the rule, so that reporting entities will know that reporting of REC serial numbers pursuant to section 95111(g)(1(M) satisfies the REC retirement requirements in the cap-and-trade regulation section 95852(b)(3)—specified imported electricity. [OP 17.05b – LADWP]

Response: ARB believes the requirements are clear. The proposed section 95111(g)(1)(M) requires reporting the serial numbers of Renewable Energy Credits (RECs) for specified imported electricity as shown below:

> *95111(g)(1)(M)3. RECs associated with electricity generated, directly delivered, and reported as specified imported electricity and whether or not the RECs have been placed in a retirement subaccount.*

If the specified source otherwise meets the delivery tracking conditions required for specified electricity imports, a nonconformance with this provision does not require using an emission factor other than the specified emission factor calculated by the ARB Executive Officer. In addition, reporting and verification pursuant to the reporting regulation does not require retirement of these RECs, only tracking. Portions of the comments related to the cap-and-trade regulation are outside the scope of this rulemaking. However, ARB staff notes that the cap-and-trade regulation requires, pursuant to section 95852(b)(3), the following:

> *The following criteria must be met for electricity importers to claim a compliance obligation for delivered electricity based on a specified source emission factor less than the default emission factor:*
>
> *….*

(D) If RECs were created for the electricity generated and reported pursuant to MRR, then the RECs must be retired and verified pursuant to MRR.

B-14b. Reporting REC Serial Numbers for Specified Imported Electricity

Comment: REC serial numbers are relevant for specific renewable import transactions, not facility registration, and should therefore be required as part of the annual emissions report. WPTF supports the proposed change to require reporting RECs associated with renewable imports, but recommends these provisions be moved (as shown below) to section 95111(a)(4) and incorporated into the annual reporting worksheet. [OP 01.03 - WPTF]

(1) *Registration Information of Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment.* The following information is required:

(A) …

(N) Retain for verification generation meter data to document that the power claimed by the reporting entity was generated by the facility or unit at the time the power was directly delivered;

…

(3) *Delivery Tracking Conditions Required for Specified Electricity Imports*

Electricity importers may claim a specified source when the electricity delivery meets any of the criteria for direct delivery of electricity defined in section 95102(a), and one of the following sets of conditions:

(A) The electricity importer is a GPE; or

(B) The electricity importer has a specified ~~written~~ power contract for electricity generated by the facilities or units.

Response: ARB believes the requirements are clear. The proposed section 95111(g)(1)(M) requires reporting the serial numbers of Renewable Energy Credits (RECs) for specified imported electricity as specified below:

95111(g)(1)(M)3. RECs associated with electricity generated, directly delivered, and reported as specified imported electricity and whether or not the RECs have been placed in a retirement subaccount.
If the specified source otherwise meets the delivery tracking conditions required for specified electricity imports, a nonconformance with this provision does not require using an emission factor other than the specified emission factor calculated by the ARB Executive Officer. In addition, reporting and verification pursuant to the reporting regulation does not require retirement of these RECs, only tracking. Portions of the comments related to the cap-and-trade regulation are outside the scope of this rulemaking. However, ARB staff notes that the cap-and-trade regulation requires, pursuant to section 95852(b)(3), the following:

The following criteria must be met for electricity importers to claim a compliance obligation for delivered electricity based on a specified source emission factor less than the default emission factor:

….

(D) If RECs were created for the electricity generated and reported pursuant to MRR, then the RECs must be *retired and verified pursuant to MRR.*

B-15. <u>Request for Additional Guidance and Transparency</u>
<u>Comment:</u> WPTF made the following request:

> *As a membership organization, WPTF has the opportunity to compare experiences of individual companies with the reporting and verification process. This shared experience suggests that reporting rules are being interpreted differently by different electric power entities, different verifiers and, in some cases, different ARB staff. While amendments to the MRR will help to clarify the rules, we believe that it is also import for ARB to provide additional guidance materials regarding questions/issues of broad interest. This could be in the form of guidance documentation or a "Frequently Asked Questions " link on the ARB cap and trade website. Development and publication of such guidance materials would help to ensure that regulation is correctly and uniformly applied by all regulated entities.*
>
> *Additionally, WPTF continues to believe that there is a strong need for ARB to establish a process by which an individual entity can get an upfront, written determination by ARB on specific reporting questions, that will provide assurance that if the entity complies with ARB's determination that it will not later be deemed to be in violation of reporting requirements for following that guidance. We note that the United States Environmental Protection Agency Petition process for resolving issues related to its reporting program3 could be used as a model.*
>
> *Finally, we are aware that ARB has been advising Open Access Technology Information (OATI) on the design of its NERC tag query for imports to California and providing training to third-party verifiers. Given the relevance of these activities for implementation of the reporting regulation by electric power entities, we believe it would be extremely useful for ARB to publish a technical document on guidance that it provides to OATI regarding NERC tag queries, and to make publicly available the training materials it has used for the verifier training sessions. Such transparency would greatly facilitate compliance with the reporting regulation by electric power entities who do not use OATI, but conduct NERC tag data queries in-house, and help all reporting entities to avoid problems arising during the verification process.*
> [OP 01.08 – WPTF]

<u>Response</u>: ARB staff appreciates the comment. ARB looks forward to continuing to work with stakeholders to ensure successful implementation of the regulation, including, if appropriate, through potential guidance or frequently-asked-questions, as suggested by the commenter. In addition, if individual questions occur, ARB staff encourages the commenter to contact them for more assistance.

B-16. Further MRR Revisions in 2013

Comment: WPTF made the following request:

> *Based on the letter to FERC Commission Moeller recently issued by ARB chairperson, Mary Nichols, WPTF anticipates that ARB will engage in rule-making next year to amend provisions of the cap and trade regulation relating to resource-shuffling. At its most basic level, implementation of a prohibition against resource shuffling determines the circumstances under which imported power must be specified and when it should be assigned the default emission rate for reporting purposes. For this reason, it is imperative that the reporting regulations and the cap and trade regulations are consistent. WPTF therefore recommends that amendments to the MRR related to electric entities, including revisions to the default emission rate for unspecified imports, be considered in conjunction with the rule-making to amend the cap and trade regulation with respect to resource shuffling.* [OP 01.09 – WPTF]

Response: Regarding portions of this comment which relate to cap-and-trade issues outside the definitional amendments which are part of this rulemaking, those comments are outside the scope of the rulemaking and this response does not address them. However, ARB will continue to coordinate the development and implementation of the reporting regulations and the cap-and-trade regulations to ensure that the two are consistent.

C. Subarticle 2. Electricity Generation and Cogeneration (§95112)

§95112 – Electricity Generation and Cogeneration Units

C-1. Support for Clarifying Changes in Sections 95112 and 95102

Comment: Commenter supports changes made in sections 95102 and 95112 that further clarify reporting of electrical and thermal output of cogeneration facilities. The modified requirements enhance ARB's ability to collect the necessary data to evaluate efficiency and GHG performance of cogeneration systems and better understand when thermal energy is being utilized rather than being vented or discharged without use. [OP 03.04a – PG&E]

Response: ARB appreciates the commenter's support.

C-2. Public Availability of Cogeneration Data

Comment: PG&E requests ARB to Make Aggregated CHP Data Publicly Available. Efficiency and GHG performance is the essential driver of cogeneration/ combined heat and power (CHP) policy in California. We ask that ARB develop and publicly present aggregated CHP efficiency information collected through the Mandatory Reporting Regulation and develop a system to cross-check the data with similar information reported to the Energy Information Administration, Federal Energy Regulatory Commission, and the California Energy Commission. We also encourage ARB to train verifiers to properly asses the validity of this data. We believe that such efforts will help inform the implementation of CHP policies, assist with the update to the

ARB's Scoping Plan scheduled for next year, and help to achieve California's AB 32 GHG reduction goals. [OP 03.04b – PG&E]

Response: The commenter's requests are noted by ARB staff. However, analysis and public availability of state-wide inventory data are beyond the scope of the proposed regulation amendments.

C-3. The Use of Cogeneration Data to Inform Efficiency

Comment: GHG Benefits or Disbenefits from Cogeneration Should Be Calculated, Aggregated, and Presented Publicly by ARB Using MRR Data. PG&E seeks clarification regarding how the data reported on CHP electrical and thermal output will be used by ARB to evaluate system efficiency and the GHG benefits of CHP. Below we describe our understanding of how the reported data could be used…..

Energy efficiency information of a cogeneration facility can further be translated into GHG emissions efficiency using a 'double benchmark' standard. Conceptually, the double benchmark compares emissions from the CHP facility to the amount of GHG emissions that otherwise would exist if the CHP Facility did not operate (and the CHP energy was supplied through separate heat and power production).

A "GHG efficient" CHP refers to one that reduces emissions as compared to the double benchmark. A "GHG inefficient" CHP refers to one that increases GHG emissions as compared to the double benchmark. The double benchmark approach was adopted as an acceptable way to determine GHG efficiency in the California Public Utilities Commission (CPUC) approved QF/CHP Settlement…..

We encourage ARB to calculate where existing CHP facilities operate in relation to a double benchmark to help inform its update to the AB32 Scoping Plan. [OP 03.05 – PG&E]

Response: The commenter has not suggested any specific regulatory amendments. The requests are noted by ARB staff, but ARB believes suggestions about updating the AB 32 Scoping Plan, and conducting an analysis and public availability of state-wide inventory data are beyond the scope of the proposed regulation amendments. Therefore, no change in rule language is made.

C-4. Aggregation of Stationary Combustion Units at a Facility Providing Power Only Inside the Facility

Comment: PG&E has two locations where stationary combustion sources are used to compress natural gas and provide electric power only inside the facility boundary. These facilities are subject to cap-and-trade obligations for the GHG emissions from sources within each facility. U.S. EPA regulations (40 CFR §98.3) permit all facility emission sources to be grouped for purposes of reporting emissions. PG&E recommends the following modifications to clarify that such aggregation is permissible under ARB's regulation as well….

"Section 95112(a). *Information About the Electricity Generating Facility*. Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating facility is required to include in the emissions data report the information listed in this paragraph, unless otherwise specified in paragraphs (e) and (g) of this section for geothermal facilities and facilities with renewable energy generation. Reporting of information specified in Section 95112(a)(4)-(6) is optional for facilities that do not provide or sell any generated energy outside of the facility boundary. [Commenter's addition:] *Notwithstanding the information specified in Section 95112(a)(1)-(3), operators of a facilities that do not provide or sell any generated energy outside of the facility boundary are not subject to the other provisions of Section 95112".* [OP 03.10 – PG&E]

Response: The commenter's requests are noted by ARB staff. However, since the original proposal did not alter this section, it is beyond the scope of the 15-day changes to address. See also Response to E-2 regarding clarifications to section 95115.

C-5. Aggregation of Cogeneration System

Comment: We propose that all electric generating facilities under 95112 be allowed to aggregate units up to the individual natural gas mains that enter the facility. For our facility and many across the state, the cogeneration facility and standby boiler come off the same natural gas main. Allowing electric generating facilities to aggregate sources up to individual gas mains will provide the most accurate possible emissions using the utility revenue meters on each natural gas main. Current regulations and amendments prevent such aggregation. Reporting in this manner would allow us to minimize reporting costs and keep ARB reporting consistent with EPA GHG reporting, which is very important in the economically changed environment. Allowing continuation of this aggregation method of reporting will allow ensure future data are consistent with historical data that has been reported since 2008 to ARB.

ARB has a desire for supplemental data for specific processes, such as standby boilers or cogeneration processes. We have no objection to providing these subgrouping data, but the meter(s) on these subgroups will not be as accurate as the utility revenue meter. As such we request that emissions for subgrouping be treated as supplemental data where acceptance of less accurate meters is allowed.

As 95112 is written today, it does not strictly allow or prohibit aggregation of sources. The aggregation of sources is a subjective decision by ARB enforced by verifiers. We request that these decisions be part of the regulation and public comment period so that all can be part of the decision. Furthermore, we ask that ARB identify clearly what sources are required to meet the fuel accuracy requirement if we can no longer use our utility revenue meter. [OP 09.01 – GPI]

Response: ARB believes the regulatory amendments already allow for aggregation of units within the same source category, and therefore, decline to make the suggested modifications. The regulation is intended to allow reporters to report fuel emissions using the accurate utility revenue meters and allow engineering estimation at the unit level, as long as the fuel quantities attributed to the units add up to the quantity measured by the accurate revenue meter. It is not the intent of ARB staff to require reporters to install additional meters at the lower level. If the sum of emissions is based on the utility revenue meter upstream, keeping up with calibration for accuracy demonstration at lower level meters is encouraged, but not required.

C-6. Accuracy of Engineering Estimates

Comment: ARB added a requirement to demonstrate accuracy of engineering estimates of energy flow to provide sufficient data quality for the state-wide inventory without the full metering and 5% accuracy requirements that are placed on data used for calculating cap-and-trade covered emissions. However, the proposed statement is unclear as to the level of accuracy required.

WSPA recommends that ARB revise the statement to: “If engineering estimation is used to report disposition of generated energy or energy flow data that are used directly to determine covered emissions or covered product, facility operators must demonstrate ± 5% accuracy of the chosen engineering estimation method.” [B 03.10 – WSPA]

Response: Energy data not used to calculate covered emissions and covered product data are currently not subject to the ± 5% accuracy standard. However, energy flow data reporting is needed to maintain the state-wide inventory mandated by AB 32, and for cap-and-trade benchmark development, energy efficiency evaluation, carbon cost distribution analysis, and informing future energy policies. Because these data are not directly used for calculating compliance obligations and allowance allocations in the carbon market, engineering estimation is allowed if the reporters do not maintain direct measurement of these energy quantities. Reporters should demonstrate that their chosen engineering estimation method will result in a reasonably accurate estimation. The rule language is intended to prevent any reporters from submitting sub-standard estimates that lack adequate justifications. The change suggested by the commenter would not prevent sub-standard estimates for energy quantities that are not directly used for determining covered emissions or covered product data under cap-and-trade. Therefore, the suggested change is not made.

C-7. Accuracy Requirement Under Unit Aggregation

Comment: ARB has proposed in Section (b) a new requirement to report cogeneration units separately from other units even though these might be included in a common pipe. The proposed change would not allow reporters to use the common pipe approach. Secondly, reporters will have to install and calibrate equipment level meters.

WSPA recommends that ARB allow reporters to use common pipe approach for calculating emissions and allow use of meters that do not meet the stringent accuracy requirements to allocate the emissions (calculated from quality assured common pipe meters) across the cogeneration and other units on the common pipe. [B 03.11 – WSPA]

Response: The existing language is intended to allow reporters to report fuel emissions using the accurate higher-level meters and allow engineering estimation at the lower or unit levels, as long as the fuel quantities attributed to the units add up to the quantity measured by the accurate higher-level meter. It is not ARB staff's intent to require reporters to install additional meters at the lower level. The staff intent explained in this response has the same effect as using the "common pipe" approach in terms of accuracy of fuel measurement, except that units at lower-level are delineated in the GHG report.

Limiting unit aggregation to units that belong to the same source category and unit type is necessary to ensure that the state-wide GHG inventory collects information in sufficient details to delineate the emissions by unit types and fuel types.

C-8. Approval of Geothermal Site-Specific Emissions Calculation Methodology
Comment: CalEnergy… requests ARB assistance with two related CalEnergy requests to the executive director in conjunction with greenhouse gas reporting. The first request is for approval of the CalEnergy methodology for calculating greenhouse gas emissions... CalEnergy worked with ARB staff to prepare a site-specific methodology for calculating greenhouse gas emissions and submitted this request for ARB executive director approval on May 25, 2012. CalEnergy has been assured by ARB staff this methodology will be approved; however, ARB staff have been unable to provide a date this methodology will be approved. ARB approval of the CalEnergy site-specific methodology to more accurately report greenhouse gas emissions is important for two reasons…

Response: The commenter's requests are noted by ARB staff. However, these comments are beyond the scope of the changes proposed in this rulemaking, and ARB therefore declines to address them here.

D. Subarticle 2. Petroleum Refineries and Hydrogen Production
(§95113 – §95114)
§95113 – Petroleum Refineries

No comments were received on section 95113.

§95114 – Hydrogen Production

No comments were received on section 95114.

E. Subarticle 2. Stationary Fuel Combustion and
Additional Industrial Sources (§95115, §95119, and §95120)

§95115 – Stationary Fuel Combustion Sources

E-1. 95115(c)(4) Choice of Tier for Calculating CO_2 emissions

Comment: The commenter objects to the provision that requires the use of a weighted mean average carbon content when more frequent (than the MRR requires) data are available. They would like the option to choose either a weighted or arithmetic mean in this case. [B 01.04 – CIPA]

Response: The requirement to use a weighted mean value instead of an arithmetic mean for fuel carbon content for Tier 3 stationary fuel combustion emission provides more accurate and consistent emissions data. There can be significant differences between weighted and arithmetic mean values. Adjustment for activity (weighting by volume of fuel combusted) is necessary to generate the most accurate data for this very significant emissions source. The inclusion of an option to use either an arithmetic or weighted mean would result in a significant and unacceptable degradation of the data quality and consistency. As such, ARB declines to make the requested change.

E-2. Aggregation of Stationary Combustion Units at a Facility Providing Power Only Inside the Facility

Comment: PG&E has two locations where stationary combustion sources are used to compress natural gas and provide electric power only inside the facility boundary. These facilities are subject to cap-and-trade obligations for the GHG emissions from sources within each facility. U.S. EPA regulations (40 CFR §98.3) permit all facility emission sources to be grouped for purposes of reporting emissions. PG&E recommends the following modifications to clarify that such aggregation is permissible under ARB's regulation as well….

"Section 95115(h). *Aggregation of Units.* Facility operators may elect to aggregate units according to 40 CFR §98.36(c), except as otherwise provided in this paragraph. Facility operators that are reporting under more than one source category in paragraphs 95101(a)(1)(A)-(B), and that elect to follow 40 CFR §98.36(c)(1), (c)(3) or (c)(4), must not aggregate units that belong to different source categories, [commenter's addition:] *unless the facility operates stationary combustion units subject to Section 95112 that do not provide or sell any generated energy outside of the facility boundary*. For the purpose of unit aggregation, units subject to 40 CFR 98 Subarticle C that are associated with one source category must not be grouped with other

Subarticle C units associated with another source category, except when 40 CFR §98.36(c)(2) applies." [OP 03.10 – PG&E]

Response: Limiting unit aggregation to units that belong to the same source category and unit type is necessary to ensure that the state-wide GHG inventory collects information in sufficient details to delineate the emissions by unit types and fuel types. The changes do not affect the overall emissions reported through the GHG reporting program. Facility operators that do not have unit level meters may use the facility revenue meter to allocate fuels to the unit level. Engineering estimation is acceptable as long as the facility operator can demonstrate to the verifier that the chosen estimation is reasonably accurate. Readers may also see Response to C-5 for an example of how facility operator may use their higher level meter for reporting fuel and emissions at lower level. Because the change in rule language is not warranted, ARB staff did not modify the rule as proposed by the commenter.

E-3. Aggregation of Units by Unit Type

Comment: 95115(h) – Aggregation of Units. ARB staff have indicated that the proposed limit to aggregation of units is not intended to require operators to install additional fuel metering equipment (to measure fuel separately for process heaters, boilers, turbines, RICEs, and flare pilots) or to subject "downstream meters" to the accuracy and calibration requirements in 95103(k), but only to require operators to utilize "engineering estimates" to allocate fuel use to, and report emissions for, individual unit types. Language should be added to the regulation to make this clear. Even so, this change would impose significant additional burden on operators and verifiers to compile the additional data, set up the additional configurations in the reporting tool, enter the additional data, and explain the reported data to a verifier. And, even though total reported emissions for the facility would be unchanged, the number of pages in a facility report could double or triple, adding further to the time to compile and verify the report. We doubt the costs associated with these additional tasks were accounted for in ARB's analysis of economic impacts. We encourage ARB staff to find less burdensome ways to obtain the additional desired data. We suggest allowing facilities to provide facility level estimates of fuel and emissions data by unit type. Such estimates would be sufficient to understand fuel use and emissions by unit type without placing significant additional burden on reporters and verifiers. [B 01.05 – CIPA]

Response: The commenter has correctly characterize the intent of the rule as "proposed limit to aggregation of units is not intended to require operators to install additional fuel metering equipment (to measure fuel separately for process heaters, boilers, turbines, RICEs, and flare pilots) or to subject "downstream meters" to the accuracy and calibration requirements in 95103(k), but only to require operators to utilize "engineering estimates" to allocate fuel use to, and report emissions for, individual unit types." The commenter's suggestion of "allowing facilities to provide facility level estimates of fuel and emissions data by unit type" is also within the construct of the existing rule proposal and reporters can report as such. No further changes to the rule language are warranted.

§95119 – Pulp and Paper Manufacturing

No comments were received on section 95119.

§95120 – Iron and Steel Production

No comments were received on section 95120.

F. Subarticle 2. Fuel and Carbon Dioxide Suppliers
(§95121 – §95123)

§95121 – Suppliers of Transportation Fuels

F-1. Suppliers of Transportation Fuels
Comment: WSPA recommends that ARB switch the order of section 95121(a)(1) and 95121(a)(2) in Section 95121 for clarity. [B 03.12 – WSPA]

Response*:* ARB staff believes that the requirements are clear in section 95121(a)(1)and 95121(a)(2); no change will be made.

F-2. Data Reporting Requirements
Comment: WSPA recommends ARB incorporate revisions to 95121(d)(5) to better clarify that refiners supplying LPG to other fuel suppliers do not need to report the emissions from this LPG. Specifically, WSPA recommends the following language be inserted into 95121(d)(5): …refiners "who supply liquefied petroleum gas to entities not licensed by the California Board of Equilization as a fuel supplier…" except for "liquified petroleum gas…" [B 03.13 – WSPA]

Response*:* All LPG sold as fuel should be reported by the refiner, however natural gas liquid (NGL) constituents sold for purposes other than for use as a 'fuel' by an end user do not fit the definition of liquefied petroleum gas (LPG), and therefore should not be reported by the refiner per section 95121. ARB believes these requirements are clear, and declines to make the changes suggested by the commenter.

F-3. Intermediate Distillate Products.
Comment: This commenter requests that ARB modify language in section 95121(a) to clearly exclude the reporting of 'straight-run petroleum intermediates' which are not suitable for sale as transportation fuels. [OP 13.01 – LTC]

Response*:* ARB staff agrees with the sentiment of this comment, and interprets the existing rules in a manner consistent with the commenter. Per section 95121(a)(2), refiners do not report any distillate products other than distillate fuel No.1 and distillate fuel No.2. Intermediate distillate products, such as “straight-run petroleum intermediates” that are not directly saleable as diesel fuel (distillate fuel No.1 or No.2) without further processing, should not be reported pursuant to section 95121. ARB staff believes that the necessary requirements are already in place in section 95121 and therefore no further revisions to the regulation were made.

§95122 – Suppliers of Natural Gas, Natural Gas Liquids, Liquefied Petroleum Gas, Compressed Natural Gas and Liquefied Natural Gas

F-4. Suppliers of NG, NGLs, LPG, CNG, and LNG
Comment: WSPA requests that ARB clarify the definitions of NGL and LPG across the MRR and cap-and trade regulations for the natural gas processing industry segment. [B 03.14 – WSPA]

Response*:* The definitions of Natural Gas Liquids (NGLs) and Liquefied Petroleum Gas (LPG) were revised in the 45-day reporting regulation language, and the revisions are consistent with the cap-and-trade regulation. No further revision is necessary.

§95123 – Suppliers of Carbon Dioxide

No comments were received on section 95123.

G. Subarticle 3. Additional Requirements for Reported Data (§95129)

§95129 – Substitution for Missing Data Used to Calculate Emissions from Stationary Combustion and CEMS Sources.

G-1. Options for Missing Data Substitution
Comment: For instances when the fuel consumption data capture rate is equal to or greater than 95.0 percent during the data year this section contains potentially costly alternatives to develop an estimate. Alternative measurement devices for each fuel flow meter would be very costly. Obtaining process data on a routine basis that would provide alternative fuel flow numbers would also, in many cases, be a costly endeavor. Note that this is for situations where 95% or more of the data is not missing.

We propose the following change (taken from language in 95129(c): 95129(d)(2)(A): Single Fuel. For missing data periods that occur when only one type of fuel is being combusted, the operator must provide substitute data for each missing data period as follows: 1. If the fuel consumption data capture rate is equal to or greater than 95.0 percent during the data year, [add] *the operator must substitute the arithmetic average of the values of that parameter immediately preceding and immediately following the missing data incident that are representative of the fuel type. If the "after" value has not been obtained by the time that the GHG emissions data report is due, the*

operator must use the "before" value for missing data substitution…
[B 03.15 – WSPA]

Response: The commenter's requests are noted by staff. However, since the original proposal did not alter section 95129, the comments are outside the scope of the amendments proposed in this rulemaking. However, ARB staff notes that even if section 95129 were part of this rulemaking, the change suggested by WSPA is not warranted since the existing language allows for the suggested substitution method.

H. Subarticle 4. Verification and Verifier Requirements
(§95130 – §95133)

§95130 – Requirements for Verification of Emissions Data Reports

H-1. Six-Year Limit for Verifiers
Comment: Commenter believes the 6-year limitation on verification bodies or verifiers "is unnecessary and creates inefficiencies as verifiers constantly move around among reporting entities." [OP 03.09 – PG&E]

Response: Staff notes the language suggestions in this section. However, the paragraphs discussed by the commenter were not modified in the original proposal, and therefore the comment is outside the scope of the 15-day changes.

H.2a. Removal of Requirement for Verification for No-Threshold Reporters.
Comment: The commenter submitted a letter of support for ARB staff's decision to remove the requirement of verification for reporters subject to non-threshold reporting, but still under the ultimate 25,000 MT CO_2e threshold for verification (for all other sectors). However, they had some reservations surrounding how this item was interpreted in prior reporting years.
[OP 14.01 – CC]

Response: ARB staff appreciates the commenter's support for these changes to remove verification requirements for reporting entities emitting less than 25,000 $MTCO_2e$. Regarding previous years, ARB believes the previous language required such verification, as specified in the Staff Report.

H-2b. Removal of Requirement for Verification for No-Threshold Reporters
Comment: The commenter appreciates that the compliance cost will be reduced for facilities that emit under 25,000 $MTCO_2e$ per year. [T 05.01 – SCPPA]

Response: See Response to H-2a.

H-3 Revisions to the Emissions Data Report

Comment: In WSPA's July 17, 2012 comment submittal, WSPA recommended ARB incorporate amendments to Section 95131(b)(9), that clarified that emissions data reports that are revised as a result of review by the verification team and involve simple reporting errors, interpretation errors, oversights or changes outside the control of the reporter, would not signify a violation, except in the circumstance where the reporter failed to submit the revised emissions data report. WSPA requests that ARB reconsider our initial comment and the following proposed language changes (in bold italics) to Section 95131(b)(9), which were set forth in our comments:

Emissions Data Report Modifications. As a result of data checks by the verification team and prior to completion of a verification statement(s), the reporting entity must make any possible improvements or corrections to the submitted emission data report, and submit a revised emission data report to ARB. ***If required improvements or corrections to the submitted report are a result of simple reporter error or simple interpretation errors, or oversight, or are outside the control of the reporter, such revisions shall not be deemed to be violations under Section 95107 for the original data report. However, f*****ailure to** ***submit a revised emissions data report*** ~~do so~~ will result in an adverse verification statement. The reporting entity shall maintain documentation to support… [B 03.16 – WSPA]

Response: In order to maintain assurance that reporting entities submit accurate data to ARB and fix correctable errors, the language change above was not made. The intent of the language in section 95131(b)(9) was to ensure the accurate reporting of both emissions and product data. In instances when corrections can be made to improve an emissions data report, they must be made. In order to make sure these changes are completed before the verification deadline, it is important to ensure that time is included in the verification completion timeline. As such, ARB declines to make the requested comment.

Regarding the comment requesting limiting section 95107, ARB notes that section 95107 was not modified as part of this rulemaking. However, section 95107(a) indicates that ARB will look to the relevant circumstances of a potential violation, including the size and complexity of the facility, any pattern of violation, and the other criteria in Health and Safety Code section 42403(b) (extent of harm caused by the violation, nature and persistence of the violation, length of time over which the violation occurs, frequency of past violations, record of maintenance, unproven or innovative nature of control equipment, any mitigating actions taken, and the financial burden to the defendant). As such, in the event ARB chose to pursue an enforcement action, the nature of the violation (i.e. a simple interpretation error), would necessarily factor into ARB's penalty analysis.

§95132 – Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers of Emissions Data Reports and Offset Project Data Reports

No comments were received on section 95132.

§95133 – Conflict of Interest for Verification Bodies

No comments were received on section 95133.

I. Subarticle 5. Requirements and Calculation Methods for Petroleum and Natural Gas Systems (§95150 – §95158)

§95150 – Definition of the Source Category

I-1 Onshore Natural Gas Processing

Comment: WSPA believes that it was not ARB's intention to exclude booster stations from the definition of this segment and recommends that ARB explicitly include booster stations in this definition. In addition, WSPA believes ARB meant to follow the EPA definition and therefore recommends modifying the definition of the segment as follows:

Onshore natural gas processing. Natural gas processing means the separation of natural gas liquid (NGLs) or ***non-methane*** gases from produced natural gas… [B 03.17 – WSPA]

Response: ARB staff agrees with the comment. The text has been modified in the 15-day proposal.

§95151 – Reporting Threshold

No comments were received on section 95151.

§95152 – Greenhouse Gases to Report

I-2a. Estimations of Gas Blowdowns on Distribution System

Comment: PG&E maintains that "using direct measurements would require significant additional time and resources…and would not yield more accurate volumes than estimation." They further argue that the data is unneeded because it is not subject to Cap-and-Trade since that data is captured under §95122 of the Mandatory Reporting Regulation. [OP 03.01 – PG&E]

Response: The blowdown GHG reporting requirements do not specify the exact method the reporter must use to derive the temperature, pressure, and volume variables required to calculate GHG emissions resulting from equipment and pipeline blowdowns. Because the emissions quantified in this section result from planned activities, the reporter may use an engineering estimate of blowdown volume and gas temperature, and derive pressure data from system control and monitoring equipment. This intent was reflected in the 15-day changes in section 95153(g).

The new requirements for blowdowns, as proposed in this regulatory update, do not take effect until 2013 data collection for reporting of 2013 data in 2014. For 2012, blowdowns will not need to be reported for the onshore petroleum and natural gas production industry segment.

I-2b. Estimations of Gas Blowdowns on Distribution System
Comment: Sempra Energy/SoCal Gas also suggests that ARB allow the use of engineering calculations for the determination of these emissions. [B 02.02 – SE]

Response: See Response to I-2a.

I-2c. Estimations of Gas Blowdowns on Distribution System
Comment: WSPA is aware that ARB amended this section to require reporters to monitor and report emissions associated with "Equipment and blowdowns" within the oilfield. Currently, reporters are not required to record blowdown events and associated parameters. Therefore, reporters would not have any information available to report for the last 9-10 months of 2012 for the 2012 MRR reporting year. In addition, pertinent operational information to assess blowdown events is unavailable, even if an BAMM was utilized. Finally, the implementation of data collection processes throughout a basin will require at least a few months before any quality assured data is obtained. Because this is a new requirement, WSPA recommends that ARB defer blowdown event reporting until 2013 and allow emissions associated with equipment blowdowns to be calculated using either (1) specific quantification methods for emissions associated with blowdowns or (2) an alternative method as specified in our comment below in Section 95154(f). [B 03.18 – WSPA]

Response: See Response to I-2a.

§95153 – Calculating GHG Emissions

I-3a. Pneumatic Devices
Comment: Commenter suggests that staff make the monitoring of non-continuous pneumatic devices optional until such time it can be shown that there would be benefits to installing metering on all devices. Furthermore, the comment recommended an updated cross-reference from §95153(a) to sub-section (b). [OP 03.02 – PG&E]

Response: ARB staff has changed the reporting requirements for intermittent bleed pneumatic devices to allow the use of emission factors (EFs) and thus treat intermittent bleed devices in the same manner as low bleed pneumatic device. This removes the 2015 metering requirement for these devices and is consistent with U.S.EPA requirements. Additionally, staff appreciates the commenter's attention to detail, and corrected the cross-reference in the 15-day changes.

I-3b. Pneumatic Devices

Comment 2: Sempra suggest that ARB should not consider intermittent bleed devices in the same category as high bleed devices and further recommends that intermittent bleed devices be excluded from the 2015 metering requirement. [B 02.01 – SE]

Response: See Response to I-3a.

I-4. Leak Surveys

Comment: Commenter notes that in §95153(o)(8)(A), they are required to conduct a leak survey every 5 years. Since this text is similar to the U.S. EPA rule, the commenter suggests that ARB issue guidance similar to the U.S. EPA's guidance on this topic; specifically, the percentage of facilities which much be surveyed each year. [OP 03.03 – PG&E]

Response: ARB staff has evaluated the guidance generated by U.S.EPA on this issue and agree with the commenter. The interpretation that U.S.EPA gives on what is considered "approximately equal across all years of the cycle" is acceptable to ARB staff.

I-5 Acid Gas Removal

Comment: The existing regulation allows two calculation methods for Method 3. Currently, reporters may use existing inlet or outlet meters to measure throughput and calculate emissions. The proposed regulation allows only inlet meter method that uses proposed Equation 4. With the proposed change, reporters will have to install and calibrate inlet meters on all AGR units and obtain additional monthly H_2S samples. The proposed requirement adds unnecessary burden on reporters to report emissions from this source category given the fact that the magnitude of emissions is very small (< 1%) or de minimis compared to total facility emissions and the percent accuracy achieved is minimal compared to the effort and costs involved.

In addition, some AGR units serve emergency flares only in compliance with local air district requirements for H_2S control. Therefore, these units are operated only during emergency situations. To comply with monthly analyses requirement, reporters will have to intentionally send gas to the flare every month for the sole purpose of taking a sample. This would violate conditions of our local air permit as well as add unnecessary criteria pollutant emissions and greenhouse gas emissions to the atmosphere.

WSPA requests ARB retain existing requirements for AGR units and require sampling only when the AGR units are in operation. [B 03.19 – WSPA]

Response: ARB agrees with the comment and has modified the requirements to allow the use of an inlet or outlet method, which is consistent with U.S. EPA requirements. In addition, ARB will require quarterly sampling, which is considerably less than a monthly requirement.

I-6. 95153(d) – Dehydrator vents

Comment: CIPA states that a "literal" interpretation of this section of the MRR would require that emissions be calculated even in cases where there were no emissions. [B 01.06 – CIPA]

Response: Onshore oil and gas production facilities are required to report emissions from dehydrator vents for all periods when emissions are occurring. If emissions from dehydrator vents do not occur during the reporting period, the reporter simply enters "zero" in the appropriate section of the reporting tool. If emissions are routed to a control device (flare) flaring emissions must be reported. No changes to the regulation are necessary.

I-7 Onshore Production Storage Tanks

Comment: The applicability of this section is unclear. It does not appear to apply to any storage tanks at California onshore production facilities. WSPA suggests that either (1) this section be deleted from the regulation or (2) language be added to the regulations that clearly states how this section applies to onshore production storage tanks. [B 03.20 – WSPA]

Response: ARB agrees with the comment and has changed the heading of section 95153(h) to directly represent the intent of this paragraph.

I-8 Associated Gas Venting and Flaring

Comment: The existing regulation allows reporters to calculate emissions from a cluster of wells within the same EIA field in lieu of a single well calculation. ARB has proposed requiring measurement of Gas to Oil Ratio (GOR) and emissions calculations at each single well. The GOR of producing wells is dependent on the characteristics of a production zone and reservoir properties. Therefore, the GOR remains similar from well to well within the same field or lease. Measuring GOR from each well in the same field or lease with hundreds to thousands of wells is unnecessarily burdensome on the operators due to the level of effort involved and cost of each test. Any accuracy achieved for the GOR is minimal compared to the total facility emissions. Most reporters have determined that these emissions are less than 1% of the total and can designate emissions from this entire source category as de minimis.

WSPA recommends ARB retain the existing monitoring and calculation method requirements for this source category. [B 03.21 – WSPA]

Response: ARB agrees with the comment and has modified the reporting requirements in 15-day language to allow emissions calculations to be based on a cluster of wells.

I-9. 95153(l) Flare stack and other destruction device emissions.
Comment: CIPA requests clarification as to whether the phrase "any applicable industry segment" applies to onshore oil and gas production facilities. CIPA also request that reporters be allowed to use actual gas HHV data (where available) rather than the default value of 1235 Btu/scf for the calculation of N_2O emissions resulting from gas combustion.
[B 01.07 – CIPA].

Response: The commenter is referred to section 95152(c)(11) of the MRR, where it is stated that reporting of flaring emissions is required for the onshore oil and natural gas production industry segment. Nitrous oxide emissions from fuel combustion represent a very small fraction of facility total emissions. The reporting requirements contained in the reporting regulation are identical to those used by facilities reporting to U.S.EPA, for consistency and ease of reporting.

I-10 Centrifugal Compressor Venting and Reciprocating Compressor Venting
Comment: ARB requires that annual measurement tests be conducted on compressors in both categories rated 250 hp or greater and that operate for more than 200 hours in a calendar year. Emissions required to be measured and reported include those associated with rod packing vents, unit isolation valve vents and blowdown valve vents. WSPA member companies have raised safety concerns regarding conducting required measurements on compressors that handle gases with high concentrations of hydrogen sulfide (H_2S). In some cases, concentrations of H_2S as high as 20,000 ppm have been noted, and while the operation of compressors is controlled and maintained, there is a safety concern regarding the potential for persons to be exposed while conducting required measurement and monitoring pursuant to this section. In addition to safety concerns associated with H_2S, WSPA is also concerned that the requirement to install temporary meters on gas lines that are tied to flares, raises the potential of introducing oxygen into the system resulting in a flammable mixture of vent gas and oxygen.

WSPA recommends ARB revise this section to allow operators the ability to petition the Executive Officer to utilize an alternative method to quantify emissions, in situations where the method is either incorrect or there exist potential safety hazards and risks. Additionally, WSPA recommends ARB clarify in this section, that because reciprocating compressor emissions associated with potential gas leaks are captured either by a vapor recovery system or piped to a combustion device (ie: flare), the emission measurement and monitoring requirements in this section would not be required.
[B 03.22 – WSPA]

Response: ARB staff is not making the recommended change. ARB staff believes sampling alternatives, such as engineering estimates, may be used when safety considerations dictate. Emissions routed to an operational vapor recovery unit (VRU) are not to be reported under this section. If VRU emissions are routed to a flare, emissions will be reported using the flaring methodology section 95153(l) of the reporting regulation. If VRU emissions are combusted as a fuel, these emissions will be reported using methods found in section 95115 of the reporting regulation.

I-11. <u>95153(m) and (n) – Centrifugal and reciprocating compressors.</u>
<u>Comment:</u> CIPA requests that an exemption from measurements be added for cases where compressor vents are "hard-piped" to closed systems such as a vapor recovery system, a fuel gas system or gas-reinjection. CIPA requests clarification concerning the requirement that measurements be made for each operating mode in which it is found for more than 200 hours in a calendar year. They also state that the requirement to determine gas composition quarterly is excessive and suggest that annual measurement or an "engineering judgment" approach would be sufficient. CIPA states that measurements should only be made in the "operating mode" the compressor is found in at the time of the annual measurement. [B 01.08 – CIPA]

<u>Response:</u> The regulation states that compressor emissions from all vents serving the compressor must be measured. If there is no venting from a compressor, then there are no venting emissions to report, and the reporter simply enters zero in the appropriate section of the reporting tool. Compressor related emissions resulting from the routing of gas to control devices such as a flare or fuel system would be reported in the appropriate section of the reporting tool. The "clarification language" suggested by the commenter…"annual measurement is to be made in each mode in which the compressor *operates* for more than 200 hours" introduces confusion and runs counter to the reporting regulation objectives. Inclusion of this language would mean that for modes such as the "pressurized – non-operating mode", no measurements would be required, since the compressor would not be "operating". However, this is a mode where emissions do occur. If the suggested change was made, a compressor could sit pressurized (but not operating) for the entire reporting period and emissions would not be measured. Quarterly sampling is also required by U.S.EPA and thus specifying quarterly sampling does not require additional measurements of gas composition. Based on these reasons, ARB has declined to make the requested changes.

I-12. <u>95153(o) and (p) Leak detection and leaker EFs and Population count and population EFs.</u>
<u>Comment:</u> The commenter points out several incorrect cross references in these sections. CIPA also requests that provisions be made to allow reporters to use "emission calculation methodologies developed by U.S.EPA and CAPCOA in combination with leak detection data already being gathered." [B 01.09 – CIPA]

<u>Response:</u> Staff appreciates the commenter's attention to detail; the errors identified in these sections have been corrected in the 15-day language. The

methodologies in these two sections have been drawn directly from U.S. EPA reporting requirements and thus are consistent with U.S. EPA GHG reporting methodologies. Given the differences inherent in the various California Air District measurement requirements for fugitive emissions, a single calculation methodology is required for consistency sake. However, to ease the regulatory burden, when measurements which are made for compliance with other regulatory programs are appropriate and applicable, they may be used to fulfill these reporting requirements.

I-13. Leak detection and leaker emission factors

Comment: This section has been revised to reflect the new 40 CFR 98 subpart W requirements. From 2011 data, fugitive emissions conservatively estimated using Subpart W population counts and emission factors are less than 1 or 2% of the total facility emissions (de minimis). With proposed leak detection, we expect a fewer number of leaks (from current LDAR programs even with a lower leak detection threshold of 2,000 PPM). Requiring leak detection for an entire hydrocarbon basin is unnecessary burden on Onshore Production reporters whose conservative fugitive emissions contribute to less than 1-2% of facility emissions.

WSPA recommends that ARB require an Onshore Production reporter to conduct leak detection only if the estimated fugitive emissions using the existing calculation method are greater than or equal to 3% of facility emissions or 20,000 MT CO_2e. Otherwise, a reporter may use existing calculation method for fugitive equipment leaks source category that uses population counts and emission factors. [B 03.23 – WSPA]

Response: ARB understands this is not a covered emission, as described in the cap-and-trade regulation. However, previous documentation from research indicates that this source has the potential to be a significant emission. ARB understands from discussions with stakeholders that they believe these emissions are small. ARB staff believes leveraging the District data, as described in Response to I-12 above, is one way to reduce the sample collection burden for this requirement. Based on this, ARB staff is not making the proposed change to this section at this time. However, ARB staff commits to working with stakeholders to ensure the successful implementation and compliance of this reporting requirement.

I-14. 95153(s) GHG volumetric emissions.

Comment 1: The commenter suggests that the two parts of this section dealing with the determination of pipeline quality and non-pipeline quality gas composition are in conflict. [B 01.10 – CIPA]

Comment 2: This section requires Onshore Petroleum and Natural Gas Production facilities to determine mole fraction of produced natural gas using annual weighted average method described in 95115(c)(4). Currently, reporters are required to do an arithmetic average of the all samples at an EIA field or lease level depending on the configuration. The number of samples varies depending on the equipment at that field/lease. To calculate annual weighted average mole fraction, reporters will have to install meters to measure gas production at all fields/leases and obtain monthly gas samples. The sum of emissions from source categories that use this calculation method range between 0.1 to 0.5% of total facility emissions (2011). The quantity is not expected to change with change in calculation method and additional monitoring burden. WSPA recommends ARB retain existing monitoring and calculation method for determining mole fraction of produced natural gas. [B 03.24 – WSPA]

Response: ARB agrees with the comment and has modified this section to allow the use of the most recent available analysis from the facility.

I-15. Crude oil, condensate, and produced water dissolved CO_2 and CH_4.
Comment 1: CIPA points out a typographic error in the variable definition section of this requirement. [B 01.11 – CIPA].

Comment 2: WSPA identified some typographical errors in the variables used in section 95153(v). They also suggested the combining of sections 95153(v) and (w) to remove any ambiguity in the reporting requirements for crude oil, condensate and produced water.

Section 95153(v) Crude and Condensate Dissolved CO2 and CH4. WSPA suggests that this section include produced water tanks which are part of the crude oil and natural gas production system. Thus the section title would read:

(v) Crude oil, Condensate, and Produced Water Dissolved CO_2 and CH_4

WSPA recommends correcting Spw to Scc in Section (v)(1)(a).

Further, WSPA recommends for clarity the following revision of the+ Vapor Recovery System Method in Subsection (v)2:

(2) Vapor recovery system method. For storage tank systems connected to a vapor recovery system, calculate the mass of CO_2 and CH_4 liberated from crude oil, condensate, and produced water (CO_2 and CH_4 total from produced fluids) by direct measurement (volume) and sampling (composition) and analysis of the vapor recovery unit (VRU) gas stream to determine the mass of CO_2 and CH_4 captured by the vapor recovery system per barrel of crude oil or condensate produced. Vapor recovery system measurements may include gases from crude oil and condensate and produced water, this can be reported as total vapor from produced fluids.

Calculate CO_2 and CH_4 emissions from the total vapor recovery system using Equation 33B:

$$E_{CO2/CH4} = (S_t * V_t)(1-(VR*CE)) \qquad \text{(Eq. 33B)}$$

Where:

$E_{CO2/CH4}$= Annual CO_2 or CH_4 emissions in metric tons.
S_t = mass of CO_2 or CH_4 recovered in a VRU per barrel of produced water.
V_t = Annual throughput of the tank in barrels (including oil, water and condensate).
VR = percentage of time vapor recovery unit was operational (expressed as decimal)
CE= Collection efficiency of the vapor recovery system (expressed as decimal).

S_t is calculated in the following steps:

1. Measure the vapor volume captured by the vapor recovery system (total scf per year)
2. Determine the mass of CO_2 and CH_4 in the gas by using the mole fraction % of each gas from an annual lab sample analysis.
3. Calculate the total yearly masses of CO_2 and CH_4 from the recovered gas using Steps 1 and 2.
4. Calculate S_t total mass of CO_2 or CH_4 per barrel of total produced fluid by dividing by the total produced fluid throughput of the tank system (oil, condensate and water)

(B) Emissions resulting from the destruction of the VRU gas stream are not exempt from reporting and the destruction device should be identified here.

[B 03.25 – WSPA], [B 03.26 – WSPA]

Response: This section and the following section (95153(w)) have been rewritten and this section has been modified. Section 95153(w) was deleted. ARB believes these changes address the stakeholders' concerns.

I-16. 95153(y) Onshore combustion emissions

Comment: CIPA requests clarification concerning the definition of pipeline quality natural gas because section 95153(y) only mentions the HHV value (omitting the CH_4 and CO_2 composition values) for pipeline quality natural gas. [B 01.12 – CIPA]

Response: Pipeline quality natural gas is defined in section 95102, in terms of the range of acceptable HHV values, and CH_4 and CO_2 composition. Furthermore, that pipeline quality gas is defined by three variables: 1) HHV, 2) CH_4 content and 3) CO_2 content. Reporters should refer to the pipeline quality natural gas definition found in section 95102 when determining which methodology they must use to calculate stationary combustion emissions.

I-17. Onshore Production Combustion Emissions

Comment: ARB has revised Section 95157(c)(19) and 95153(y), which would require reporters to calculate and report stationary and portable combustion emissions, including fuel type, unit type and combustion type. As a result, reporters would no longer be able to utilize common pipe metering as allowed under Section 95115. The proposed revisions would essentially eliminate the ability for operators to utilize current metering systems that involve common pipe metering, and instead they would have to install additional meters to report emissions by fuel type, unit type and combustion type. WSPA believes it was not ARB's intent to eliminate the ability of operators to utilize "common pipe" metering; rather, this revision appears to have been an oversight that occurred in the process of incorporating EPA Subpart W requirements into the MRR regulation.

WSPA recommends ARB revise Section 95153(y) and Section 95157(c)(19), to allow operators the ability to retain existing calculation and reporting methodologies, including common pipe metering, for Stationary Combustion equipment and to meet aggregate reporting requirements for portable equipment. [B 03.27 – WSPA]

Response: According to section 95153(y)(2)(A), the operator may use company records to determine fuel volume. Because we do not define company records, we feel that a company record could include records related to the common pipe that transfers fuel to the particular unit in question and other units. This allows a reporter to use the existing common pipe method in section 95115 of the reporting regulation, with proper documentation to show to their verifier, while allowing ARB to collect accurate data in a more cost-effective manner. Based on this, ARB does not believe the requested change is necessary.

§95154 – Monitoring and QA/QC Requirements

I-18. Best Available Monitoring Methods

Comment: ARB has proposed best available monitoring methods for only certain sources categories for 2012. However, ARB has proposed several changes that are not currently included as covered by BAMM. Petroleum and Natural Gas Systems facilities are subject to numerous new monitoring and reporting requirements for entire basin that are being applied retroactively for 2012 and with very little time (couple months at the most) to implement the changes before January 1, 2013. From our 2011 experience, we have learned that having BAMM availability for only certain specific parameters is not enough. WSPA requests BAMM for all new proposed requirements for Petroleum and Natural Gas Systems for 2012 and 2013.

It is understood that BAMM will no longer be available after January 1, 2013. WSPA is concerned that situation may arise in the future where an alternative to the reporting methods would be needed in order to meet the requirements of the regulation. As noted in Section 95152(n) above, WSPA believes ARB should provide the ability for operators to propose alternative methods of quantifying emissions, in the event the method required poses potential safety issues.

WSPA suggests that the following language (in bold italics) be added to the first paragraph of Section 95153 (Calculating GHG emissions) to provide the ability for operators to propose alternative methods to quantifying emissions: The operator of a facility must calculate and report the annual GHG emissions as prescribed in this section. The facility operator who is a local distribution company reporting under section 95122 of this article must comply with section 95153 for reporting emissions from the applicable source types in section 95152(i) of this article. ***If the facility operator determines that there is the absence of an error in the calculation methodologies in this section or there are other factors involving safety or there are outside the control of the operator, that result in the inability to obtain the required emission data and would results in reporting errors, the operator can petition the ARB to use an alternative calculation methodology, and use of such methodology is subject to approval by the Executive Officer.*** [B 03.28 – WSPA]

Response: At this time, ARB is not planning to make the suggested change because it is not consistent with how we treat other sectors that have this issue. As an option for reporters that experience unexpected problems, section 95129(h), entitled *Procedure for Approval of Interim Fuel Analytical Data Collection Procedure During Equipment Breakdowns*, gives the option of a petition for certain circumstances. For instances of equipment breakdown under the reporting regulation, ARB interprets 'fuel analytical data' to include all information related to the measurement of GHG emissions. This would allow reporters the ability to recommend an alternative collection method in cases of unexpected circumstances.

§95155 – Procedures for Estimating Missing Data

No comments were received on section 95155.

§95156 – Additional Data Reporting Requirements

I-19. 95156(a)(11) – Additional data reporting requirements.
Comment: CIPA requests clarification as to the consequences of the voluntary reporting of annual product information for 2011 and 2012 product data (section 95156(a)(11)) related to allowance allocation. CIPA also states that the installation of additional meters to determine production data may not be feasible and suggests that reporting of product data be voluntary for 2013 as well. [B 01.13 – CIPA]

Response: The product data reporting requirements for 2011 and 2012 are voluntary. A facility may choose to report and verify this information. Beginning with 2013 data, the full reporting requirements for product data are in effect. During verification, a verifier will ask the facility if they have any product data. If the reporter answers in the affirmative, the verifier will, at a minimum, note a non-conformance with regards to product data. It is important that the reported data is accurate and complete. Product data reported to ARB is used in the cap and trade program and may affect the allocation of allowances to individual facilities.

I-20. Cogeneration Data Reporting
Comment: *Section 95156. The Proposed Additions to Address Cogeneration Should Be Clarified.* Requirements related to reporting of total thermal output and net electricity generation output from cogeneration at onshore and

offshore petroleum and natural gas production facilities in section 95156 (at the basin level) should be more clearly connected to what is required at the unit and facility level pursuant to section 95112. The requirement in section 95156(a)(3)(A) and (B) to assess the “portion of CO_2e emissions associated with” either thermal or electric output without a clear methodology for conducting this allocation may be problematic. (ARB previously included a method for conducting such an allocation of emissions between energy streams in the 2007 versions of section 95112 of the regulation, which was subsequently deleted.) PG&E recommends that this language be eliminated so that the section reads as follows:… (remove “the portion of CO_2e emissions associated with this…” phrase from 95156(a)(3)(A), (B), and (C)) [OP 03.06 – PG&E]

Response: The additional data items added to the proposed amendment can be calculated from the information already collected under section 95112. Staff agrees that availability of a uniform and consistent method for such emissions distribution is essential for regulatory purpose. Staff has removed the language as suggested by PG&E.

I-21. Additional Data Reporting Requirements

Comment: ARB has proposed several requirements (Section 95156(a)) to report additional data for Onshore Petroleum and Natural Gas Production operators. Most of the reporting requirements for cogeneration facilities are redundant because these facilities are already subject to 95112 reporting requirements. In addition, ARB has not proposed a method for data collection, monitoring, and calculating the additional data. The allocations of facility CO_2e to electricity, steam, thermal EOR, nonthermal EOR have not been proposed. In the absence of a regulatory calculation method, it is impossible to have uniform methods of interpretation across the industry and verifiers resulting in some facilities being subject to more stringent requirements than others. WSPA recommends that ARB include calculation methods for these parameters specified for reporting. In addition, WSPA recommends that any redundancy in reporting information is minimized. [B 03.29 – WSPA]

Response: The modifications to section 95156 were made to support the cap-and-trade allocation of allowances process. ARB staff has removed the language in section 95156 (a)(3)(A)-(C) that required “the portion of CO_2e emissions associated with this generation.” In regards to redundant reporting, the Cal-eGGRT reporting tool is not setup to easily collect the information required for the cap-and-trade program because the methods used to calculate the information are more flexible. For example, in sections 95156(a)(4)-(5), best available methods may be used to report the required information as opposed to more stringent methods outlined in section 95112. While the use of best available methods may lead to different methods, it is important to have this flexibility to ensure the reporting of this information because in many cases the information may not be readily accessible to the reporter. ARB staff encourages the reporters of this information to contact ARB with their choice of methods.

I-22 Natural Gas Fractionators – Product Data

Comment: ARB has proposed several requirements (Section 95156(d)) to report additional product data for Onshore Natural Gas Processing operators. Natural Gas fractionators are already required to report these parameters under section 95122.

WSPA recommends ARB minimize any redundancy in reporting information. [B 03.30 – WSPA]

Response: The language regarding the product data requirements for natural gas fractionators was moved from section 95122(f) to section 95156(d). The requirements are located in only one location of the reporting regulation.

§95157 – Activity Data Reporting Requirements

I-23. 95157(d) – Definition of "annual throughput".

Comment: CIPA requests clarification as to what "annual throughput" is to be reported. [B 01.14 – CIPA].

Response: Section 95157(d) requires reporting of "annual throughput as determined by engineering estimate based on best available data for each industry segment listed in paragraphs (a)(1) through (a)(8) of this section".

For instance, 1) for a facility reporting as a transmission/compression facility, annual throughput would be the total amount of natural gas passing through their facilities in a reporting year, 2) for an LNG storage facility "throughput" would be the mass of NG passing through their storage facility, and 3) for an onshore natural gas and petroleum production facility, throughput would be the amount of natural gas produced annually.

ARB staff will seek further clarification from U.S. EPA to ensure that "throughput" reported to ARB is defined in the same manner as when reporting to U.S.EPA. Reporters should report the same "throughput" value to ARB that they report to U.S. EPA.

§95158 – Records that must be Maintained

No comments were received on section 95158.

J. Other 45-Day Comments Received.

J-1. Proposed Amendments to the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms.

Comment: CIPA questions the need for a cap-and-trade program and laments what they characterize as severe compliance costs, complexity, leakage problems, and the less than 100% allocation of allowances to emitters. CIPA again restates their objection to the facility definition adopted by ARB for the onshore petroleum and natural gas industry segment used in the MRR. [B 01.15 – CIPA]

Response: Comments concerning the cap-and-trade program, beyond the conforming definitional amendments discussed in the Staff Report and this FSOR, are outside the scope of this document. The changes proposed in Appendix B to the Staff Report ensure that the reporting and cap-and-trade regulations are in sync and do not conflict with each other. The reporting regulation has been designed to support the cap-and-trade program and thus it must generate the required data for major GHG emission sources in California and also ensure data accuracy and consistency requisite for a viable cap-and-trade program. In contrast, the U.S. EPA reporting requirements are presently designed to provide data for a national GHG inventory, with less rigorous reporting requirements. Please see Response to A-6 for information with regards to the facility definition for onshore petroleum and natural gas production.

J-2. Comment: WSPA provided general comments in support of the stakeholder process and references their written comments which were submitted to the Board. They also stated they had issues around the accuracy of data reporting that were included in their written comments. [T 01.01 – WSPA]

Response: ARB staff has reviewed the comment letter submitted by WSPA and addressed them in this FSOR.

J-3. AB 32 Cost of Implementation Fee Regulation
Comment: A concerned citizen voices opposition to fees being added to industry to cover the cost of implementation by the ARB. They feel it is clearly only a tax that will be passed on to consumers in the end. [OP 07.01 – LML]

Response: ARB staff notes the citizen's comment and thanks her for her participation in the public process. However, this comment is outside the scope of this rulemaking and it is unclear what specific changes, if any, the commenter is recommending. Only conforming definitions are being made to the fee regulation through this process.

J-4. Tracer Enthalpy Testing
Comment: Commenter's initial GHG reporting method uses tracer enthalpy testing to determine the amount of heat removed from the geothermal resource and the ARB default emission factor. This method was approved by staff in 2010, and commenter worked with staff to prepare a site-specific methodology for calculating GHG emissions, submitting this request for approval by the Executive Officer in May, 2012. They have concerns that the methodology will not be approved since they have not heard a confirmation back from ARB at this time. Additionally, the commenter mentions that in June 2012, ARB approved their usage of Sulfer Hexafluoride (SF_6) to perform tracer enthalpy testing, and will continue to do so until such time a better method is developed. [OP 15.02 – CEOC]

Response: This comment is outside of the scope of this rulemaking. ARB staff will follow up with the commenter outside of this FSOR document.

J-5. Penalties
Comment: Commenter appreciates ARB staff's willingness to work together to resolve issues. Additionally, they reiterate their hesitance to support the language of the regulation without some acknowledgement that there is a limitation on the ability of ARB to put the full penalty of the state behind something that may have begun as an inadvertent or minor error.
[OP 16.01 – CCEEB]

Response: ARB staff appreciates the positive comments. The portion of the comment that addresses section 95107 is outside the scope of this regulatory process. However, as noted during the Board hearing, ARB has committed to putting together guidance documents which specifically address the commenter's request for further guidance on enforcement-related issues, in particular looking at the responses provided to similar comments in the FSOR for the 2010 amendments to the reporting regulation.

J-6a. Guidance and FSOR
Comment: Commenter notes the lengthiness of ARB's FSOR documents, and suggests that ARB staff condense the document into a smaller number of pages, for ease of use. [OP 16.02 – CCEEB]

Response: Please see Response to J-5. While this comment is outside the scope of this regulatory update process, ARB staff will continue to work with the stakeholders to ensure the enforcement requirements are clearly outlined and explained.

J-6b. Guidance and FSOR
Comment: Commenter indicates that they are working with CCEEB and look forward to engaging in the process of developing a guidance document as well. [T 01.02 – WSPA]

Response: See response to J-6a.

J-6c. Guidance and FSOR
Comment: Commenter indicates they would support any guidance on enforcement area because Health and Safety Code is quite lengthy.
[T 07.01 – PG&E]

Response: See response to J-6a.

J-7. Reporting and the State Water Project
Comment: The State Water Project appreciates the work that the Board has done to understand the unique circumstances of the commenter. The commenter looks forward to continued dialogue with ARB on their issues.
[T 04.01 – SWC]

Response: ARB staff thanks the commenter and will continue to work them on issues, as needed.

J-8. Cost Effectiveness of the Proposed MRR Revisions

Comment: In the ISOR's discussion of the cost and economic impacts of the MRR revisions, ARB acknowledges that one of the proposed rule amendments that may lead to a noticeable change in costs is "additional monitoring and reporting requirements for oil and gas production entities." This is but a truism and we certainly agree with this statement. In particular, the additional costs associated with gathering data and calculating, reporting, and verifying emissions for Subpart W emission source categories in accordance with the MRR's stringent requirements is out of balance with the amount of emissions associated with these sources.

Facilities that reported emissions for calendar year 2011 generally found that the additional effort associated with calculating and reporting emissions for these sources exceeded 50% of the total effort for the 2011 data reports, yet accounted for relatively small amounts of emissions (i.e. less than 3% of total facility emissions, which were generally reported as de minimus). When it came to verification of the 2011 data reports, the effort was even more out of balance, i.e., most of the questions raised by verifiers and most of the reporters' efforts to respond to questions during verification were associated with Subpart W sources. Increasing the stringency of requirements for these sources will only increase the imbalance that already exists between effort (cost) and reported emissions.

We are also concerned that these cost impacts tend to be disproportionately distributed to smaller entities. This is because smaller entities tend to operate facilities that are less concentrated and centralized, increasing the effort to gather data and calculate and report emissions (e.g., more oil and water samples needed to calculate emissions from more oil and water storage facilities). We note that Table VI-2 of the ISOR indicates that 21 of the 26 oil and gas production facilities affected by the MRR are "small" or "medium" facilities.

Finally, for comments related to additional cost impacts that ARB may not have accounted for in its analysis of cost and economic impacts of the proposed amendments to the MRR, see our specific comments below regarding:

95115(h) – Aggregation of Units: and
95156 – Additional Data Reporting Requirements
[B 01.16 – CIPA]

Response: The commenter indicated that the amount of effort for the subarticle 5 reporting is for a relatively small amount of the emissions. This was the first year of reporting subarticle 5 emissions to both ARB and U.S. EPA. With the data reported this year, ARB staff will be able to evaluate the magnitude of the emissions reported as a sector to subarticle 5. In many cases, an individual facility may have more air quality control devices on their equipment as opposed to another and therefore have a variation in the emissions data reported to ARB. As the reporting of this section develops, ARB staff is committed to evaluating the efficacy of the methods and the magnitude of emissions. Additionally, as the verifiers become familiar with the reporting requirements in subarticle 5, the overall costs may decline.

The commenter elaborated on their concerns regarding the costs associated with unit aggregation requirements under another comment that they labeled as “95115(h) – Aggregation of Units” in their comment letter. Staff provided additional clarifications to address their concerns regarding unit aggregation under Response to E-3. As explained in Response to E-3, reporters are allowed to report aggregated units by providing facility level estimates of fuel and emissions data by unit type according to the way they proposed in comment letter. Therefore, with such unit aggregation practices, the cost associated with unit aggregation is marginal.

The cost is also considered marginal for the additional reporting requirements for section 95156. Most of the emissions are already being reported to ARB under section 95112. However, as indicated in Response to I-21, the methods are much more flexible and do not require the same metering requirements.

J-9 Appreciate Working Relationship
Comment: PG&E appreciates the time and effort ARB staff put in with them on many of the reporting rule amendments. [T 07.02 – PG&E]

Response: ARB staff thanks the commenter for this comment and looks forward to working with the commenter in future.

15-DAY COMMENTS
AND STAFF RESPONSES

K. Subarticle 1. Applicability, Definitions, and General Requirements (§95101 – §95103)

§95101 – Applicability

No comments were received on section 95101.

§95102 – Definitions

K-1 Covered Product Data Definition
Comment: The MRR proposed revision adds a new definition for “Covered Product Data” (Section 95102(111)) that “means all product data included in

the allocation of allowances under sections 95870, 95890, 95891 of the cap-and-trade regulation, regardless of whether the cap-and-trade regulation imposes a compliance obligation for the data year." The MRR proposed revision to 95103(k) further states that the accuracy requirements of (k) "apply to data used for calculating covered emissions and covered product data."

In reviewing the definition and intent with ARB, there seems to be a general understanding that "covered product data" was intended to apply only to "Finished Products" – (Section 95113(l)(1) and Primary Refinery Products (Section 95102(354)). This issue should be clarified so that all stakeholders and verifiers clearly understand the ARB's intent.

Recommendation: WSPA supports ARB Staff's opinion that the term "Covered Product Data" is intended to apply to Primary Refinery Products as defined in Section 95102(354)) and "Finished Products" as used in Section 95113(l)(1) and suggests the definition be amended as follows:
"Covered Product Data" means Primary Refinery Products as defined in Section 95102(354)) and "Finished Products" as used in Section 95113(l)(1)" [F 03.09 – WSPA]

Response: The proposed fifteen-day revisions did not alter the definition for "covered product data" and are therefore are not officially open for comment. However, to clarify for the commenter, "covered product data" is a term which applies to product data produced by a spectrum of industries, and is not limited to products produced by refineries.

K-2 Revise Electricity Importer Definition
Comment: SCPPA states that the definition of "electricity importer" in section 95102(a)(140) of the MRR should be further revised to clarify which entity is considered to be the electricity importer if there is no NERC e-Tag. Currently, the definition refers to "the facility operator or scheduling coordinator" without specifying the order of priority of those two types of entities. SCPPA's proposed edits are shown below. [FF 04.04 – SCPPA]

(140) "Electricity importers" deliver imported electricity. For electricity that is scheduled with a NERC e-tag to a final point of delivery inside the state of California, the electricity importer is identified on the NERC e-Tag as the purchasing-selling entity (PSE) on the last segment of the tag's physical path with the point of receipt located outside the state of California and the point of delivery located inside the state of California. For facilities physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission or~~and~~ distribution system when the electricity is not scheduled on a NERC e-Tag, the importer is the ~~facility operator or~~ scheduling coordinator or the functional equivalent, or if there is no entity performing this function, the facility operator. Federal and state agencies are subject to the regulatory authority of ARB under this article and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and California Department of Water Resources (DWR).

Response: See Response to A-5a.

K-3 Revise Generation Providing Entity Definition

Comment: SCPPA states that the definition of "generation providing entity" or "GPE" in section 95102(a)(216) of the MRR refers to the GPE as being "recognized by the ARB," for the reason that ARB does not intend to establish a formal recognition process for GPEs. SCPPA's proposed edits are shown below. [F 04.05 – SCPPA]

(216) "Generation providing entity" or "GPE" means a facility or generating unit operator, full or partial owner, party to a contract for a fixed percentage of net generation, sole party to a tolling agreement with the owner, or exclusive marketer ~~recognized by ARB~~ that is either the electricity importer or exporter with prevailing rights to claim electricity from the specified source.

Response: See Response to A-8a.

K-4a. Revise Power Contract Definition

Comment: SCPPA supports the proposed changes to the definition of "Power contract" in section 95102(a)(351) of the MRR, but considers that these changes do not go far enough to provide clarity in all circumstances. SCPPA proposes certain additional changes to this definition (shown below) which would increase its clarity. [F 04.05 – SCPPA]

(351) "Power contract," ~~or "written power contract,"~~ as used for the purposes of documenting specified versus unspecified sources of imported and exported electricity, means an agreement ~~written document~~, including written, ~~associated~~ verbal or electronic records ~~if included as part of the written power contract~~, arranging for ~~the procurement of~~ an electricity transaction. Power contracts may be, but are not limited to, power purchase agreements, enabling agreements, electricity transactions, and tariff provisions, without regard to duration, or ~~written~~ agreements to import or export on behalf of another entity, as long as that other entity also reports to ARB the same imported or exported electricity under section 95111(c)(4) or section 95111(a)(6). A power contract for a specified source is a contract that is contingent upon delivery of power from a particular facility, unit, or asset-controlling supplier's system that is designated at the time the transaction is executed.

Response: See Responses to A-12a and A-12b.

K-4b. Revise Power Contract Definition

Comment: LADWP states that the power contract definition should be broadened to recognize electronic as well as written agreements, and proposed the following revisions. [F 05.01 – LADWP]

(~~301~~351) "Power contract" ~~or "written power contract,"~~ as used for the purposes of documenting specified versus unspecified sources of imported and exported electricity, means an agreement ~~written document~~, including written, ~~associated~~ verbal or electronic records ~~if included as part of the written power contract~~, arranging for ~~the procurement of~~ an electricity transaction. Power contracts may be, but are not limited to, power purchase agreements, enabling agreements, electricity transactions, and tariff provisions, without regard to duration, or ~~written~~ agreements to import or export on behalf of another entity, as long as that other entity also reports to ARB the same imported or exported electricity under section 95111(c)(4) or section 95111(a)(6). A power contract for a specified source is a contract that is contingent upon delivery of power from a particular facility, unit, or asset-controlling supplier's system that is designated at the time the transaction is executed.

Response: See Responses to A-12a and A-12b.

K-4c. Revise Power Contract Definition

Comment: LADWP asks whether new 15-day language will apply only to new contracts beginning January 1, 2013 onward, or whether it will apply to existing contracts and agreements. LADWP requests clarification that it does not apply to pre-existing contracts and arrangements to import or export electricity on behalf of another entity that have already been recognized in previous GHG emission reports submitted to ARB. [F 05.02 – LADWP]

Response: See Responses to A-12a and A-12b.

§95103 – Greenhouse Reporting Requirements

No comments were received on section 95103.

L. Subarticle 2. Electric Power Entities (§95111)

§95111 – Electric Power Entities

L-1a Asset Controlling Supplier Status

Comment: In the event an ACS receives an adverse verification opinion on its annual report, LADWP encourages ARB to consider assigning emissions to the ACS in accordance with 95103(g) in lieu of revoking the ACS status, in order to avoid emission factor shock to the downstream purchasers of electricity supplied by the ACS. LADWP proposes the following revisions.

Asset-controlling suppliers must annually adhere to all reporting and verification requirements of this article, or be removed from asset-controlling supplier designation. ~~Asset-controlling suppliers will also lose their designation if they receive an adverse verification statement, but may reapply in the following year for re-designation.~~

[F 05.03 – LADWP]

Response: See Response to B-3b.

L-1b. Asset Controlling Supplier Status

Comment: LADWP asks whether new 15-day language will apply only to new contracts beginning January 1, 2013 onward, or whether it will apply to existing contracts and agreements. LADWP requests clarification that it does not apply to pre-existing contracts and arrangements to import or export electricity on behalf of another entity that have already been recognized in previous GHG emission reports submitted to ARB. [F 05.02 – LADWP]

Response: See Response to B-3a - B-3b.

L-2. Revocation of Asset Controlling Supplier Status

Comment: Sections 95111(a)(5) and (b)(3) will permit entities in addition to the Bonneville Power Administration to be recognized as Asset Controlling Suppliers. SCPPA supports this. However, section 95111(f)(5) provides for Asset Controlling Suppliers to lose their designation as being Asset Controlling Suppliers if they receive an adverse verification statement. This provision does not make it clear that the revocation of an Asset Controlling Supplier's status as being an Asset Controlling Supplier would have only a prospective effect on the calculation of emissions associated with imports from the Asset Controlling Supplier. The possibility of a retroactive effect would cause uncertainty in the market. ARB staff informed SCPPA in a teleconference on October 22, 2012 that any revocation of Asset Controlling Supplier status would have only a prospective effect, due to the operation of section 95111(b)(3). As the provision on revocation does not reference this part of section 95111(b)(3), it would be helpful to include additional guidance on this issue in the FSOR or guidance materials, to reassure entities that purchase power from Asset Controlling Suppliers. The guidance should clearly state that the loss of Asset Controlling Supplier status will not have a retroactive effect on the emission factor associated with purchases of electricity from the affected Asset Controlling Supplier. [F 04.03 – SCPPA]

Response: See Response to B-3a.

L-3a. Clarify REC Reporting Provisions in 95111(g)(1)(M)
Comment: SCPPA understands that ARB does not intend that the requirement to report the retirement status of renewable energy credits (RECs) should prevent an importer from claiming an RPS adjustment before retiring the associated RECs. Accordingly, SCPPA urges that section 95111(g)(1)(M) be amended to clarify that reporting whether RECs are retired or not does not prevent an importer from using unretired RECs to claim electricity for the RPS adjustment. If this section cannot be amended in the current proceeding, this clarification should be provided in the FSOR and/or in guidance materials. [F 04.01 – SCPPA]

Response: See Responses to B-12 and B-13a-e.

L-3b. Clarify REC Reporting Provisions in 95111(g)(1)(M)
Comment: LADWP states that the link between the reporting of REC information under the MRR and satisfying the REC retirement requirement in 95852(b)(3) and 95852(b)(4) of the cap and trade regulation is missing. It should be made clear that if an entity satisfies the REC reporting requirement in 95111(g)(1)(M), then the entity may claim a source-specific emission factor for imported renewable energy that is directly delivered, and/or can claim the RPS Adjustment for imported renewable energy that is not directly delivered. LADWP recommends the following revisions. [F 05.04 – LADWP]

(1) *Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment*. The following information is required:

***

(M) An electricity importer may claim a source-specific emission factor for renewable energy that is directly delivered, and/or the RPS Adjustment for renewable energy that is not directly delivered, if the electricity importer ~~P~~provides the primary facility name, total number~~, serial numbers~~ of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the RECs as specified below:

1. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment as well as whether the RECs:

a) ~~H~~have been placed in a retirement subaccount and designated as retired for the purpose of compliance with the California RPS program.

b) Will be placed in a retirement subaccount and designated as retired for the purpose of compliance with the California RPS program within 36 months from the date of generation.

2. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment in a previous emissions data report year that ~~later~~ were subsequently withdrawn from the retirement subaccount or modified, the associated emissions data report year the RPS adjustment was claimed, and the date of REC withdrawal or modification.

3. RECs associated with electricity generated, directly delivered, and reported as specified imported electricity and whether or not the RECs have been, or will be, placed in a retirement subaccount within 36 months from the date of generation.

(N) For verification purposes, retain meter generation data to document that the power claimed by the reporting entity was generated by the facility or unit ~~at the time the power was directly delivered~~.

Response: See Response to B-12.

L-4a. Generation Meter Data Requirements in 95111(g)(1)(N)
Comment: SCPPA requests that ARB provide guidance on information required to be retained to satisfy section 95111(g)(1)(N). SCPPA notes that although ARB staff stated preference for hourly data, requiring hourly data would result in considerable volumes of data that would take time to compile, review and verify, and that some utilities may not have access to this hourly data. ARB should carefully consider what data is needed for the RPS adjustment. Monthly data may be adequate. Specific guidance on the data requirements should be included in the MRR guidance materials.
[F 04.02 – SCPPA]

Response: See Response to B-11.

L-4b. Generation Meter Data Requirements in 95111(g)(1)(N)
Comment: LADWP states that the language added to 95111(g)(1)(N) should be modified. It is impractical to verify that power was generated by the facility or unit at the time the power was directly delivered. Therefore, the phrase "at the time the power was directly delivered" should be removed from this requirement. [F 05.05 – LADWP]

Response: See Response to B-11.

M. Subarticle 2. Electricity Generation and Cogeneration, Stationary Fuel Combustion, and Other Sources

§95112 – Electricity Generation and Cogeneration Units

M-1. Aggregation of Cogeneration System.
Comment: The commenter simply resubmitted its comments already submitted during the 45-day comment period. [F 01.01 – GPI]

Response: See Response to C-5.

M-2. Aggregation of Cogeneration Systems
Comment: ARB has revised Section 95112(b) requiring reporters to report cogeneration systems separate from other types of equipment that might be part of a common pipe configuration. This would prevent reporters from using upstream common pipe metering and require reporters to install and use equipment level meters to report by each electricity generation unit. It is our understanding that this was not ARB's intent. To address this issue WSPA recommends the following changes to the proposed changes:

(b) Information About Electricity Generating Units. Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating unit must include in the emissions data report the information listed in this paragraph. For aggregation of electricity generating units, the operator must meet the applicable criteria in 40CFR §98.36(c)(1)-(4), ~~unless otherwise specified in sections 95115(h) and95112(b)~~. For an electricity generation system (a cogeneration system, a bigeneration system, a combined cycle electricity generation system, or a system with boilers and steam turbine generators), the operator may aggregate all the units that are integrated into the system for the purpose of reporting data to ARB. Operators of Part 75 units may also aggregate units to the system level according to this paragraph, notwithstanding the limitation in 40 CFR §98.36(d)(1)(i). ~~If there is more than one system present at the facility, each system must be reported separately. For electricity generating units that are not part of an integrated generation system, aggregation of electricity generating units is limited to units of the same type, as specified in section 95115(h).~~ Operators of geothermal facilities, hydrogen fuel cells, and renewable electricity generating units must follow paragraph (e), (f), or (g) of this section, whichever is applicable, instead of paragraph (b) of this section. For bottoming cycle cogeneration units, the operator is not required to report the data specified in section 95112(b)(4)-(6) except for any fuels combusted for supplemental firing as specified in section 95112(b)(7).
[F 03.01 – WSPA]

Response: See Response to C-7, where ARB staff responded to similar comments submitted by the commenter during the 45-day comment period. Clarifications in Response C-7 are provided to alleviate the commenter's concerns, and therefore, no change to the rule language is made.

§95115 – Stationary Fuel Combustion Sources

M-3. Aggregation of Stationary Fuel Combustion Units

Comment: ARB has revised Section 95115(h) limiting the aggregation of stationary fuel combustion units to the defined unit type categories of boilers, reciprocating combustion engine, turbine, process heater, and other (none of the above). This would prevent reporters from using upstream common pipe metering and require reporters to install and use equipment level meters to report by unit types as listed in this section. It is our understanding that this was not ARB's intent.

Recommendation: WSPA recommends the following edits to the proposed changes in order to clarify ARB's intent:

(h) Aggregation of Units. *Facility operators may elect to aggregate units according to40 CFR §98.36(c), except as otherwise provided in this paragraph. Facility operators that are reporting under more than one source category in paragraphs 95101(a)(1)(A)-(B) and that elect to follow 40 CFR §98.36(c)(1), (c)(3) or(c)(4), must not aggregate units that belong to different source categories. For the purpose of unit aggregation, units subject to 40 CFR 98 Subarticle C that are associated with one source category must not be grouped with other Subarticle C units associated with another source category, except when 40 CFR §98.36(c)(2)applies. ~~Aggregation of stationary fuel combustion units is limited to units of the same type, where the unit type categories are: boiler, reciprocating internal combustion engine, turbine, process heater, and other (none of the above). Units subject to section 95112 must use the criteria for aggregation in section 95112(b).~~ Facility operators that choose to aggregate units according to the common stack provision in 40 CFR §98.36(c)(2) may report emissions according to 40 CFR§98.36(c)(2), but they must separately report the heat input (MMBtu) by fuel type for each individual unit or each group of units ~~of the same type, such that the grouping of units still meets the limitations for unit aggregation specified elsewhere in this paragraph~~.* [F 03.02 – WSPA]

Response: See Responses to E-2, E-3, and C-5, which provide clarifications to alleviate the commenter's concerns. Therefore, no changes to the rule language are made.

N. Subarticle 2. Suppliers of Transportation Fuels

§95121 – Suppliers of Transportation Fuels

No comments were received on section 95121.

O. Subarticle 3. Additional Requirements for Reported Data

§95129 – Substitution for Missing Data Used to Calculate Emissions from Stationary Combustion and CEMS Sources.

O-1. Missing Data Provisions

Comment: This section is confusing and could be misconstrued. Recommendation: We recommend for fuel data that are missing no more than 5% for the year, the reporters may develop best available estimation method to substitute the missing data. The reporter may exercise their good judgment in coming up with a reasonable estimation approach. If the reporter has other upstream or downstream fuel measurement points, fuel consumption recorded at upstream/downstream during the missing data period can be used for the estimation.

Best available method may include, but is not limited to, substituting with the average of before or after values if such average is reasonably representative of the missing data period. If there is reason to think that the before-and-after average may not be representative of the missing data, the reporter should look to available process data or production data that are routinely measured and recorded at the unit and use those as the basis for estimation. The reporter must be able to convince the verifier of the reasonableness and the best-availability of the chosen approach. [F 03.09 – WSPA]

Response: The commenter's requests are noted by staff. However, since the original proposal did not alter section 95129, the comments are outside the scope of the amendments proposed in this rulemaking. However, ARB staff notes that even if section 95129 were part of this rulemaking, the change suggested by WSPA is not warranted since the existing language allows for the suggested substitution method.

P. Subarticle 5. Requirements and Calculation Methods for Petroleum and Natural Gas Systems (§95150 – §95158)

§95150 – Definition of the Source Category

No comments were received on section 95150.

§95153 – Calculating GHG Emissions

P-1 Centrifugal and reciprocating compressors.

Comment: On September 20, 2012, CARB revised Subpart W to require annual compressor vent measurements for all 3 modes of operation if operating hours in each mode exceeds 200 hours. This language deviates from EPA subpart W language that requires an annual measurement in each mode that a compressor is found. SCG would like to emphasize the importance of harmonized regulations to ease the reporting obligation and to ensure that consistent emissions are reported as State and Federal levels.

The change in language has the potential to cause a severe burden to SCG. In 2011, SCG had a total of 40 compressors that were subject to Subpart W. These compressors are located in facilities from Los Angeles to the Arizona border. It would be an overwhelming task for our centralized engineering group to manage up to 120 separate measurements each year. It is likely that measurements will be required at multiple sites at the same time, requiring additional resources, equipment and training. In addition, it is possible that measurements may be required towards the end of the year as the 200 hour threshold is approached. Any unplanned shutdown of a compressor may be enough to trigger Subpart W requirements. In summary, the rule will require a loss of flexibility to schedule site visits over the year and a level of uncertainty due to tie inclusion of the 200 hour threshold.

The benefits of such a change in rule language are questionable. GHG emissions in the 2 non-operation modes (standby/pressurized and depressurized) are negligible compared to the operating mode, meaning that the additional burden does not result in a decidedly more accurate inventory. SoCalGas suggests that ARB revise the calculation requirements to be consistent with the existing EPA regulation. [F 02.01 – SCG]

Response: The current U.S. EPA reporting requirements dictate that measurements be made “for each compressor in the mode in which it is found during the annual measurement.” This is problematic because the “emissions picture” at a compressor plant can vary quite significantly depending on when the reporter choses to make the “annual measurement.” Actual emissions may well be significantly higher or lower depending on the operational status of the multiple compressors across the entire reporting period. Thus to construct an accurate and representative annual emissions inventory for a compressor station, measurements must be conducted for each compressor in each mode in which the compressor operates for a significant period of time. The 200 hour threshold was chosen to insure that emissions were measured for each compressor in each mode that the compressor operates for a significant period during the reporting period. The U.S. EPA method provides only a “snap-shot” of emissions at an arbitrarily chosen time, which is very different from an accurate assessment of compressor emissions in all operating modes. Based on these reasons, ARB declines to make the suggested changes.

P-2. Centrifugal and Compressor Venting and Reciprocating Compressor Venting
Comment: In our letter dated September 20, 2012, WSPA commented on Section 95153(m) and (n) for centrifugal and reciprocating compressor venting. In our letter, we noted that ARB requires that annual measurement tests be conducted on compressors in both categories rated 250 hp or greater and that operate for more than 200 hours in a calendar year. Emissions required to be measured and reported include those associated with rod packing vents, unit isolation valve vents and blowdown valve vents. WSPA raised in our letter, member company safety concerns regarding conducting required measurements on compressors that handle gases with high concentrations of hydrogen sulfide (H_2S). In some cases, concentrations of H_2S as high as 20,000 ppm have been noted, and while the operation of compressors is controlled and maintained, there is a safety concern regarding the potential for persons to be exposed while conducting required measurement and monitoring pursuant to this section. In addition to safety concerns associated with H_2S, WSPA is also concerned that the requirement to install temporary meters on gas lines that are tied to flares, raises the potential of introducing oxygen into the system resulting in a flammable mixture of vent gas and oxygen.

ARB indicated the possibility of utilizing certain sections in the MRR (ie: Section 95109(b)) to allow operators the ability to petition the Executive Officer to utilize an alternative method to quantify emissions, in situations where the method is either incorrect or there exist potential safety hazards and risks.

Recommendation: WSPA reiterates its previous comments and requests ARB clarify in the final MRR regulation that operators may be able to utilize Section 95109(b), to either use an alternative method comprising of either a "test" or "engineering" or "other appropriate" method to quantify GHG emissions.

Additionally, WSPA reiterates its previous comment seeking ARB to clarify in this section, that if reciprocating compressor emissions associated with potential gas leaks are captured either by a vapor recovery system or piped to a combustion device (ie: flare), the emission measurement and monitoring requirements in this section would not be required. [F 03.03 – WSPA]

Response: ARB is not making the proposed change. The safety of personnel is of paramount concern. ARB has provided sampling options in 95154(a)(4). In this section, reporters are directed to use an optical gas imaging instrument for sources that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface. Additionally, as indicated in Response to I-10, ARB has developed clarifying language indicating that reporters should report emissions from the combustion (via flare or combustion device) of vented emissions in the appropriate section and they are not required to conduct emissions measurements where and when these emissions are combusted elsewhere.

In this case, section 95109(b) is not applicable because it not consistent with the intent of the section, which is to allow more accurate or just-as-accurate methods to be used for emission quantification.

P-3. Leak Detection and Leaker Emission Factors
Comment: ARB has revised this section to require onshore production operators to conduct annual leak detection on all fugitive components. This section requires that operators physically conduct leak detection using 40 CFR Part 60 methodology and other very prescriptive leak detection sampling methods. WSPA would like to note that the requirements of this section will impose potential operational burdens and significant cost to measure minimal emission that would not have a compliance obligation under the Cap and Trade regulation, if finalized. Further, WSPA would like to point out that California's air district inspection and maintenance programs have shown that the actual emissions identified by these I&M programs are significantly lower than the emissions estimated using the 40 CFR Part 60 methodology. WSPA believes that the proposed amendment will impose significant costs to operators to measure minimal emissions that would not even be covered by the overall Cap and Trade program, if finalized.

We note the following issues with the proposed leak detection method:

- Emissions estimated using the proposed Leak Detection method (95153(o)) are exempt from Cap and Trade compliance obligation as stated in 95852.2(b)(10).
- Fugitive emissions data reported to ARB for 2011 (95153(p)) shows that the new proposed leak detection method (95153(o)) is an attempt to increase accuracy of a small amount of emissions that are already small.
- Use of the 95153(p) methodology, will result in onshore operators reporting at least (estimated) 100 times more leaks than would have been expected based on leaks found in 2011 using the air district LDAR programs.
- As the existing air district LDAR programs do not cover heavy crude components or components with gas content less than 10% VOC, onshore production operators would have to conduct **additional** leak detection. However, requiring this additional leak detection for an entire hydrocarbon basin is an unnecessary economic burden on Onshore Production reporters.

    - In the Initial Statement of Reasons for Rulemaking, dated August 1, 2012, ARB staff stated in Table VI-1a (Summary of State-Wide Incremental Costs for Private Businesses) that the incremental 10-year cost to the Oil & Gas Production Industry Sector would be $259,000 for the entire rule amendment. WSPA has determined based on a de-identified and aggregated survey of representative industry facilities, that this is a significant underestimation of costs associated with the proposed changes. Based on our estimation, the 10-year incremental cost to the Oil & Gas Production Industry

<u>Sector for revised Section 95153(o) alone may exceed $25 million (or $2.5 million/year).</u>

This amount is nearly **100 times the ARB estimate** of costs over the 10-year period, again to measure insignificant emissions that do not have an obligation under the Cap and Trade program.

- Moreover, assuming a conservative assumption that fugitive emissions account for 2% of total facility emissions, an average <u>annual</u> cost per ton for additional leak detection would be approximately $10 per metric tonne (MT) of CO2e for a source category that is exempt from compliance obligation.

Recommendation: WSPA believes that proposed leak detection to determine fugitive emissions within an onshore production facility is not cost effective for facilities whose fugitive emissions are insignificant. Therefore, WSPA recommends that ARB require an onshore production reporter to conduct leak detection only if the estimated fugitive emissions using the existing calculation method are greater than or equal to 3% of facility emissions or 20,000 MT CO2e. Otherwise, a reporter may use the existing calculation method that uses population counts and emission factors for this fugitive equipment leaks source category. [F 03.04 – WSPA]

<u>Response:</u> See Response to I-12. Additionally, ARB staff believes the cost estimate proposed by the commenter for subarticle 5 is overestimated and it is not clear what methods the commenter used to calculate the costs. ARB believes its cost estimates included in the Staff Report are representative of the anticipated cost. However, ARB staff commits to working with stakeholders to ensure the successful implementation and compliance of this reporting requirement.

P-4. <u>Onshore Production Combustion Emissions</u>

<u>Comment:</u> ARB has revised Section 95153(y) requiring reporters to calculate pipeline quality natural gas combustion using any Tier of Section 95115 and field gas combustion using calculation method specified in 95153(y)(2). There are several issues associated with this proposed change.

Recommendation: WSPA recommends the following changes to the proposed requirements:

(y) Onshore petroleum and natural gas production and natural gas distribution combustion emissions. *Calculate CO2, CH4, and N2O combustion-related emissions from stationary or portable equipment, except as specified in paragraph (y)(3) and (y)(4) of this section as follows:*

(C) Calculate ~~GHG~~CO2 volumetric emissions ~~at actual conditions using Equations 35 and 36 of this section:~~ using Tier 3 calculation methodology as described in Section 95115.

~~$E_{a,CO2} = (V_a * Y_{CO2}) + \eta * \Sigma V_a * Y_j * R_j$ (Eq. 35)~~
~~$E_{a,CH4} = V_a * (1-\eta) * Y_{CH4}$ (Eq. 36)~~

~~Where:~~
~~$E_{a,CO2}$ = Contribution of annual CO_2 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.~~
~~V_a = Volume of fuel gas sent to combustion unit in cubic feet, during the year.~~
~~Y_{CO2} = Concentration of CO_2 constituent in gas sent to combustion unit.~~
~~$E_{a,CH4}$ = Contribution of annual CH_4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.~~
~~η = Fraction of gas combusted for portable and stationary equipment determined using an engineering estimation. For internal combustion devices, a default of 0.995 can be used.~~
~~Y_j = Concentration of gas hydrocarbon constituent j (such as methane, ethane, propane, butane and pentanes plus) in gas sent to combustion unit.~~
~~R_j = Number of carbon atoms in the gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus, in gas sent to combustion unit.~~
~~Y_{CH4} = Concentration of methane constituent in gas sent to combustion unit.~~

(D) Calculate N_2O and CH_4 mass emissions using Equation 37 of this section.

$$Mass_{N2O\ or\ CH4} = (1*10^{-3}) * Fuel * HHV * EF \quad \text{(Eq. 37)}$$

Where:
$Mass_{N2O\ or\ CH4}$ = Annual N_2O or CH_4 emissions from the combustion of a particular type of fuel (metric tons N_2Oor CH_4).
Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).
HHV = For the higher heating value for field gas or process vent gas, use actual HHV of the gas or default 1.235×10^{-3} mmBtu/scf for HHV.
EF = Use 1.0×10^{-4} kg N_2O/mmBtu and 0.001 kg CH_4/mmBtu.
1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) Operators may omit e~~E~~xternal fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr ~~do not need to~~ from reporting combustion emissions under this section or section 95115 or ~~include these emissions~~ for threshold determination in section 95101(e). The operator must report the type and number of each external fuel combustion unit.

(4) Operators may omit i~~I~~nternal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr (or equivalent of 130 horsepower),~~do not need to~~ from reporting combustion emissions under this section or section 95115 or ~~include these emissions~~ for

threshold determination in section 95101(e). The operator must report the type and number of each internal fuel combustion unit. [F 03.05 – WSPA]

Response: See Response to I-17.

§95154 – Monitoring and QA/QC Requirements

No comments were received on section 95154.

§95156 – Additional Data Reporting Requirements

P-5 Additional Data Reporting Requirements
Comment: ARB has revised the reporting requirements of this section to include reporting of emissions associated with thermal and electricity output, purchases, and sales in addition to reporting of facility level emissions. It is our understanding that these additional five types of reporting requirements are not subject to verification requirements of MRR but are necessary to make policy decisions. However, all reporters and verifiers may be unclear as to which reported data points are subject to verification and which ones are not. ARB has explained recently that all data points reported under Section 95157 are not subject to verification requirements of MRR.

Recommendation: In order to clearly identify data points subject to verification and those that are not, WSPA recommends ARB to move reporting requirements that are not subject to verification to Section 95157.

§ 95156. Additional Data Reporting Requirements.

Operators must conform with the data reporting requirements in section 95157 except as specified below.

(a) In addition to the data required by section 95157, the operator of an onshore and offshore petroleum and natural gas production facility must report the following data disaggregated within the basin by each facility that lies within contiguous property boundaries:

(1) CO2e emissions, including CO2, CH4, and N2O as applicable for the source types specified in section 95152(c);
(2) For combustion sources for which emissions are reported, fuel use by fuel type;
(3) For cogeneration sources:
(A) Total thermal output (MMBtu);
(B) Net electricity generation (MWh);
(C) Amount of electricity generation (MWh) not consumed within the facility(i.e., exported offsite or to another facility owner/operator);
(4) For steam generator sources:
(A) Total thermal output (MMBtu) ~~and the CO2e emissions associated with this output~~;

(B) Thermal output (MMBtu) not utilized within the facility (i.e., exported offsite or to another facility owner/operator) ~~and the CO2e emissions associated with this output~~;
(5) For electricity generation sources not included in section 95156(a)(3):
(A) Net electricity generation (MWh) ~~and the CO2e emissions associated with this generation~~;
(B) Amount of electricity generation (MWh) not consumed within the facility (i.e., exported offsite or to another facility owner/operator) ~~and the portion of CO2e emissions associated with this generation~~;
(6) Total steam (MMBtu) utilized but not generated at the facility ~~and the CO2eemissions associated with this output, if known~~;
(7) Barrels of crude oil produced using thermal enhanced oil recovery;
[F 03.06 – WSPA]

Response: During a verification, the verification body evaluates the emissions and product data for material misstatement (covered emission data and covered product data) and conformance (see section 95131(b)(10)). Conformance checks include making sure all of the data reporting requirements were met, as well as methodological checks, as needed. The commenter indicates that verification is not required; however, this is not the case. Verification is required for the complete emissions data report, which includes conformance and material misstatement checks. ARB staff believes the regulatory requirements are clear in describing which elements of section 95156 are required to be verified for material misstatement and which are required for conformance checks. As such, ARB declines to make the changes suggested by the commenter.

§95157 – Records that Must Be Retained

P-6. Vented and Flared Emissions

Comment: The proposed revisions to Section 95157(c) say that "Both the vented and flared emissions will be reported under respective source types and not under flare source type." This is in conflict with what has been ARB guidance for reporting flare emissions in the Emissions Reporting Tool, which has allowed reporting of all flare emissions as flare emissions only. For flares that serve multiple sources but measure only the combined process stream at the flare, a requirement to apportion total flare emissions to individual sources feeding the flare will require the use of estimation techniques that may have significant error, rendering the results questionable (though total reported flare emissions are accurate). Please consider dropping the requirement to apportion flare emissions to individual sources, even if it applies only to the Activity Data Workbook and not to the Emissions Reporting Tool.
[F 02.01 – MS]

Response: The section 95157(c) reporting requirement covers the reporting of “Activity Data” and as such is only subject to conformance checks during verification. To comply with this requirement, reporters must make a “good faith" effort to apportion their flaring emissions by source type. Additionally, this reporting does not require additional effort on the part of facilities reporting in California since they must comply with this reporting requirement for U.S. EPA. As such, ARB declines to make the requested change.

P-7. Activity Data Reporting Requirements
Comment: ARB has revised the reporting requirements of this section to include reporting of stationary combustion emissions by unit type in paragraph (c)(19). From WSPA's conversations with ARB, it is our understanding that the activity data reporting requirements of this section are not subject to verification requirements of MRR but are necessary to make policy decisions. However, all reporters and verifiers may be unclear as to which reported data points are subject to verification and which ones are not.

Recommendation: In order to clearly identify data points subject to verification and those that are not, WSPA recommends ARB to clearly state that reporting requirements of Section 95157 are not subject to verification as follows:

§95157. Activity Data Reporting Requirements.

In addition to the information required by section 95103, each annual report must contain reported emissions and related information as specified in this section. Data reported under this section are not subject to the verification requirements of this regulation. [F 03.08 – WSPA]

Response: See Response to P-5. ARB staff is not making this change because conformance checks during verification are required for section 95157.