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

Public Hearing Date: October 25, 2013

Agenda Item No.: 13-9-8

November 18, 2013

This page is intentionally blank

TABLE OF CONTENTS

I. Introduction

A. General

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). The regulation was 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 and September 2012.

On September 4, 2013, ARB issued a notice of public hearing to consider the proposed amendments at the Board's October 25, 2013 hearing. A "Staff Report: Initial Statement of Reasons for Rulemaking" (Staff Report) was made available for public review and comment starting September 4, 2013. 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 Attachment A to the Staff Report. All references relied upon and identified in the Staff Report were also made available to the public on September 4, 2013. These documents were also posted to ARB's internet web site at: **http://www.arb.ca.gov/regact/2013/ghg2013/ghg2013.htm**

At its October 25, 2013 public hearing, the Board considered staff's proposal for adoption. The proposed revisions correct or clarify various reporting requirements necessary for the submittal of complete and accurate emission data reports, and add or modify data elements for product data reporting necessary to support the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation (title 17, California Code of Regulations, section 95800 et seq.)(Cap-and-Trade program) and the statewide greenhouse gas inventory.

At the hearing, written and oral comments were received. The Board adopted Resolution 13-43, 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 13-43 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 13-43 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 were released on October 28, 2013 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 28, 2013 to November 15, 2013. These amendments clarify existing calculation methods and reporting requirements and support benchmarking and allocation of allowances for the Cap-and-Trade program.

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 No. R-13-007 on November 18, 2013 approving the regulation with the modifications described in Section II of this FSOR.

B. Mandates and Fiscal Impacts to Local Governments and School Districts

The Board has determined that this 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 of approximately $2,535 per year for 21 local government entities.

Economic Impacts on Small Businesses

Staff has evaluated small businesses based on reporting requirements from 2012. After a thorough evaluation of the reported data, staff determined that there are no small businesses subject to this regulation in California.

Updates to the Economic Analysis

The final incremental estimated cost for these regulatory amendments dropped considerably when compared to the original cost in the Initial Statement of Reasons (ISOR). The revised cost estimate indicates an overall cost saving of almost $6 million dollars over eight years compared to the estimated cost of $56 million over eight years described in the ISOR. The main reason for the estimated cost decrease was the removal of metering requirements for purposes of monitoring emissions from oil well completions and workovers. The originally proposed amendment for oil well completions and workovers was replaced with non-metered activity data requirements, which staff believes still provides ARB with needed data, while reducing costs. Additional cost savings in this updated estimate comes from adding flexibility for emissions from equipment leaks for the onshore petroleum and natural gas production industry segment. The other sectors' (lead production, food processors, petroleum refineries, etc.) cost estimates remain fairly constant when compared with the estimates in the ISOR and represents an overall incremental cost increase.

C. 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 discussion of alternatives to the initial regulatory proposal is provided in Chapter II-D of the Staff Report. Alternatives to the proposed regulations that were considered include: taking no action (i.e., retaining the existing rule) and adding qualitative data requirements.

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 Program 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 September 4, 2013, as described in the Staff Report, were released on October 28, 2013. The amendments approved for adoption by the Board clarify calculation methods and support the Cap-and-Trade program. The modifications released for public comment on October 28, 2013, were made in light of comments received prior to and during the Board hearing, and make clarifications to definitions, increase the rigor of reported data, and further support 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 28, 2013, with comments due on November 15, 2013. 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 amendments. 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, 95110, 95111, 95112, 95113, 95114, 95115, 95116, 95117, 95118, 95119, 95120, 95121, 95122, 95123, 95124, 95129, 95130, 95131, 95132, 95133, 95150, 95151, 95152, 95153, 95154, 95155, 95156, and 95157 and Appendix B, 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 September 4, 2013 were made available to the public for review and comment on October 28, 2013. 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 Attachment 1 to the Notice of Public Availability of Modified Text at the reporting regulation webpage at: http://www.arb.ca.gov/regact/2013/ghg2013/ghg2013.htm

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

Modifications to Section 95102. Definitions.

In response to stakeholder comments and feedback, staff has proposed amendments to clarify definitions related to the product data listed in section 95102(b). Additionally, staff included a new section of definitions, section 95102(c), to support the Complexity Weighted Barrel (CWB) efficiency metric in the originally proposed amendments. Staff has withdrawn proposed changes to the definitions of first point of receipt and source of generation in section 95102(a). Other definitional changes in section 95102(a) support the 15-day proposed amendments in other sections of the reporting regulation.

Modifications to Section 95103. Greenhouse Gas Reporting Requirements.

Staff has proposed to modify language in section 95103(h) to specify implementation of reporting requirements for 2013 data reported in 2014. Staff addressed electric power entity stakeholder comments in section 95103(h)(8) by clarifying language to specify the effective date for certain contract and asset controlling supplier requirements in section 95111. Additional language was removed from section 95103(k) to ensure consistent metering requirements for all covered product data, including the CWB. These changes are necessary to ensure reporting entities understand the timing of implementation and metering requirements of the regulation.

Modifications to Section 95104. Emissions Data Report Content and Mechanism.

In order to ensure consistency with regulatory provisions in the AB 32 Cost of Implementation Fee Regulation (title 17, California Code of Regulations, section 95200 et seq.), staff has proposed to move the originally proposed language regarding increases and decreases in facility emissions from section 95104(e) to section 95104(f), and to retain section 95104(e) for the reporting tool requirement. The proposed change re-letters these provisions. In addition, and based on stakeholder comments, staff has proposed to modify the language related to increases and decreases in facility emissions (now shown in section 95104(f)) by replacing the references to criteria pollutants and toxic air contaminants with references to greenhouse gas emissions. These modifications shown in section 95104(f) include submittal of qualitative information regarding increases or decreases in greenhouse gas emissions, a threshold limiting the reporting of the increases or decreases to differences of greater than five percent from the previous year, and clarify that there are no verification requirements for this paragraph. These changes are necessary to ensure reporting under this paragraph is consistent with the greenhouse gas reporting requirements of this article.

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

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

In response to stakeholder comments, staff has withdrawn originally proposed regulatory amendments associated with: supporting documentation for busbar claims in section 95111(a)(4)(A)(3); use of the transmission loss factor in sections 95111(a)(5)(D) and 95111(b)(3); path outs in section 95111(a)(5)(E); modifications of the meter data requirement in section 95111(g)(1)(N); system power reporting in sections 95111(a)(12) and 95111(b)(5) and references in sections 95111(g) and 95111(g)(6); and treaty power in sections 95111(b)(3) and 95111(f)(5)(F). After reviewing stakeholder comments, staff determined that these originally proposed amendments were not appropriate at this time. Withdrawing these originally proposed amendments ensures consistent reporting with previous reporting years and the proposed changes to withdraw those originally proposed amendments are necessary to ensure reporting entities understand their reporting obligations.

Additionally, and in response to stakeholder comments, staff indicated in the Notice of Public Availability of Modified Text its intent to issue revised statements in this FSOR to effectively withdraw the seller control interpretation for asset controlling suppliers associated with section 95111(a)(5)(B) initially stated in the Staff Report. This change is needed to ensure electric power entities know how to effectively report their purchases of asset controlling supplier power. These statements can be found in staff's response to comments concerning section 95111(a)(5)(B).

Modifications to Section 95113. Petroleum Refineries.

In conjunction with the inclusion of CWB in the originally proposed amendments, in response to stakeholder comments, and to ensure clarity of reporting, staff has proposed to remove references to the Carbon Dioxide Weighted Tonne (CWT) methodology and replace them with CWB. This includes adding an equation to calculate the CWB in section 95113(l)(3)(B), corrections to the catalytic cracking CWB factor in section 95113(l)(3)(C), specifications on density and measurement accuracy in 95113(l)(3)(D)-(E) and a new Table 1 to the section that describes the CWB factor for each throughput. These changes are necessary to support the revised Cap-and-Trade program benchmarking and allocation of allowances for the refining sector.

Modifications to Section 95115. Stationary Fuel Combustion Sources.

Staff has proposed modifications to the product data reporting requirements of section 95115(m) which are consistent with stakeholder comments requesting slightly altered definitions and names of certain products. The altered names are reflected in this section. These changes are necessary to ensure consistent product data reporting.

Modifications to Section 95119. Pulp and Paper Manufacturing.

In response to a stakeholder comment, staff updated section 95119(d) to further clarify the reporting requirements related to data aggregation and sampling frequencies for tissue products.

C. Modifications to Subarticle 3 – Additional Requirements for Reported Data

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

Staff has proposed modifications to section 95129(c)(3) to clarify the missing data provisions for carbon content and fuel data for cases when less than 80 percent of data is available. These changes are necessary to avoid a gross over estimation of emissions and to ensure reporting entities are able to accurately utilize the originally proposed regulatory amendments.

D. Modifications to Subarticle 4 – Requirements for Verification of Greenhouse Gas Emissions Data Reports and Requirements Applicable to Emissions Data Verifiers; Requirements for Accreditation of Emissions Data and Offset Project Data Report Verifiers

Modifications to Section 95131. Requirements for Verification Services.

Staff has proposed modifications to section 95131(b)(8)(F)(1) to clarify the verifier requirements for conformance checks. Additional updates to section 95131(b)(14) removed references to the CWT for consistency with section 95113(l)(3).

Modifications to Section 95132. Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers of Emissions Data Reports and Offset Project Data Reports.

Staff has corrected a grammatical error in this section.

Modifications to Section 95133. Conflict of Interest Requirements for Verification Bodies.

In order to clarify what constitutes a high conflict of interest, staff has proposed changes to section 95133(b)(2) to assist verification bodies and reporting entities better evaluate potential conflicts of interest. This change was needed to ensure reporting entities and verification bodies understand the verification requirements.

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

Modifications to Section 95152. Greenhouse Gases to Report.

The requirements for crude oil well venting during well completions and workovers was removed from section 95152(c)(6) based on stakeholder feedback. Instead, the crude oil well venting during completions and workovers were moved to section 95157(c)(6). The reporting requirement in section 95152(c)(8) was renamed to ensure consistency with the term in section 95153(h). Lastly, reporting emissions from pipeline main equipment leaks was added to section 95152(i)(9) to ensure reporting consistency with the United States Environmental Protection Agency's (U.S. EPA) Greenhouse Gas Reporting Rule for the natural gas distribution industry segment. These changes were made in response to stakeholder comments and are necessary to ensure clarity in the reporting requirements.

Modifications to Section 95153. Calculating GHG Emissions.

In response to stakeholder comments, staff has proposed removing the metering requirement for oil well workovers and completions which was included in the originally proposed amendments in section 95153(f). Removal of this requirement is consistent with the modifications to section 95152(c)(6). The heading for section 95153(h) was modified back to "Dump Valves" for consistency with section 95152(c)(8). Staff has proposed a clarifying modification to section 95153(k) for flexibility with reporting of associated gas venting and flaring. The modification in section 95153(p) was added to ensure pipeline main equipment leaks are reported correctly. A wording edit was made to section 95153(v)(1)(A)(1) to improve clarity in the provision. Lastly, staff has proposed modified language to clarify the monthly reporting requirements for non-pipeline quality natural gas in section 95153(y)(2) and the method for the gas composition of each hydrocarbon stream. These changes are necessary to improve the clarity of reporting under this section, to respond to stakeholder concerns about cost without hampering accuracy requirements, and to ensure reporting entities understand their reporting requirements.

Modifications to Section 95156. Additional Data Reporting Requirements.

Based on stakeholder comments, staff has proposed modified language in section 95156(c) to clarify the specific types of facilities that must report natural gas liquids. This change is needed for improved clarity.

Modifications to Section 95157. Activity Data Reporting Requirements.

In response to stakeholder comments, staff has added activity data requirements for gas and oil well completions and workovers in section 95157(c)(6). These changes further clarify how reporting entities must report. Additionally, minor typographical edits were made in sections 95157(c)(18) and 95157(c)(19).

F. Non-Substantive Corrections to the Regulation

After the close of the 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.

1. <u>Correction of citation:</u> A citation in section 95124 incorrectly refers to the missing data provisions from the previously incorporated Title 40 Code of Federal Regulations (CFR), §98.225 of the U.S. EPA Reporting Rule, rather than incorporated §98.185 of the same federal rule. This citation has been corrected in order to avoid erroneous and inapplicable data being generated. These two sections of the U.S.EPA Reporting Rule were incorporated by reference when amendments to the reporting regulation were adopted in December 2010.

The above described modifications constitute non-substantial changes to the regulatory text because they more accurately reflect the numbering of a section and correct spelling and grammatical errors, but do not materially alter the requirements or conditions of the proposed rulemaking action.

III. DOCUMENTS INCORPORATED BY REFERENCE

Below is a list of documents incorporated by reference, as specified in the Staff Report and as further modified by the 15-day Notice of Public Availability of Modified Text. The section of the reporting regulation which incorporates each specific document is shown in parentheses following the description of each document:

1. ASTM D-70 – 09 "*Standard Test Method for Density of Semi-Solid Bituminous Materials (Pycnometer Method),*" 2010. (Appendix B)
2. ASTM D-287 – 92 "*Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method),*" 2006. (Appendix B)
3. ASTM D-1945 – 03 "*Standard Test Method for Analysis of Natural Gas by Gas Chromatography,*" 2003. (Appendix B)
4. ASTM D-2597 – 94 "*Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography,*" 2004. (Appendix B)
5. ASTM D-3710 – 95 "*Standard Test Method for Boiling Range Distribution of Gasoline and Gasoline Fractions by Gas Chromatography,*" 1999. (Appendix B)
6. ASTM D-3588 – 98 "*Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels,*" 2003. (Appendix B)
7. ASTM D-4007 – 08 "*Standard Test Method for Water and Sediment in Crude Oil by the Centrifuge Method,*" 2008. (Appendix B)
8. ASTM D-4052 – 09 "*Standard Test Method for Density, Relative Density, and API Gravity of Liquids by Digital Density Meter,*" 2009. (Appendix B)
9. ASTM D-5002 – 99 *"Standard Test Method for Density and Relative Density of Crude Oils by Digital Density Analyzer,"* 2010. (Appendix B)
10. ASTM D-5504 – 08 "*Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence,*" 2008. (Appendix B)
11. ASTM D-6228 – 10 "*Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Flame Photometric Detection,*" 2010. (Appendix B)
12. California Health and Safety Code, Part 3 of Division 26, commencing with Section 40000. *Air Pollution Control Districts.* http://www.leginfo.ca.gov/cgi-

bin/calawquery?codesection=hsc (accessed August 22, 2013). (Section 95102(a))

13. EPA Method 15 "*Determination of Hydrogen Sulfide, Carbonyl Sulfide, and Carbon Disulfide Emissions from Stationary Sources,"* 1996. (Appendix B)
14. EPA Method 16 "*Semicontinuous Determination of Sulfur Emissions from Stationary Sources,"* 1996. (Appendix B)
15. EPA Method 8021B "*Aromatic and Halogenated Volatiles By Gas Chromatography Using Photoionization And/or Electrolytic Conductivity Detectors,"* 1996. (Appendix B)
16. EPA Method 8260B "*Volatile Organic Compounds by Gas Chromatography/Mass Spectrometry (GC/MS),"* 1996. (Appendix B)
17. EPA Method TO-14 "*Determination of Volatile Organic Compounds (VOCs) In Ambient Air Using Specially Prepared Canisters with Subsequent Analysis by Gas Chromatography,"* 1999. (Appendix B)
18. EPA Method TO-15 "*Determination of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters and Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS),"* 1999. (Appendix B)
19. GPA 2174 – 93 "*Analysis Obtaining Liquid Hydrocarbon Samples For Analysis by Gas Chromatography,"* 1993. (Appendix B)
20. GPA 2177 – 03 "*Analysis of Natural Gas Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography,"* 2003. (Appendix B)
21. GPA 2261 – 00 "*Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography,"* 2000. (Appendix B)
22. GPA 2286 – 95 "*Extended Gas Analysis Utilizing a Flame Ionization Detector,"* 1995. (Appendix B)
23. ISO 12625-8:2010 "*Tissue paper and tissue products -- Part 8: Water-absorption time and water-absorption capacity, basket-immersion test method*," International Standards Organization, 2010. (Section 95102(b))
24. ISO 50001 "*Energy Management Systems – Requirements with Guidance for Use*," International Standards Organization, 2011. (Section 95130)
25. *"Official Methods of Analysis of the Association of Official Analytical Chemists*," 13th Ed., 1980, sections 32.025 to 32.030, under the heading "Method III (Potentiometric Method)." (Section 95102(b))
26. "*Official Methods of Analysis of the Association of Official Analytical Chemists*," 13th Ed., 1980, sections 32.014 to 32.016 and 52.012. (Section 95102(b))
27. *"Standards for Gas Service in the State of California, General Order No. 58A*." State of California, Public Utilities Commission, 1992. (Section 95103(k))
28. ASTM D189 - 06(2010)e1 "Standard Test Method for Conradson Carbon Residue of Petroleum Products," 2010. (Section 95102(c))

29. CRC Handbook of Chemistry and Physics, CRC Press Inc., Boca Raton 83rd Edition, 2002 – 2003, Section 3-1, Physical Constants of Organic Compounds. (Section 95113(l)).

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.

Documents Previously Incorporated by Reference, now Deleted

The following references from the original proposal are no longer included as references in the final regulation order due to 15-day changes:

1. Definition of Volatile Organic Compounds (VOC). 40 CFR Part 51.100(s). United States Environmental Protection Agency. March 31, 2009. http://www.epa.gov/ttn/naaqs/ozone/ozonetech/def_voc.htm (accessed August 2, 2013) (Section 95102(a))
2. Definition of Toxic Air Contaminant. California Health and Safety Code, Section 39655(a). http://www.leginfo.ca.gov/cgi-bin/displaycode?section=hsc&group=39001-40000&file=39655 (accessed August 2, 2013) (Section 95102(a))
3. *Columbia River Treaty: Treaty between Canada and the United States of America relating to Cooperative Development of the Water Resources of The Columbia River Basin*, January 17, 1961. (Section 95102(a))

IV. 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/2013/ghg2013/ghg2013.htm

This rulemaking is for amendments to the ARB mandatory reporting program. However, a few comments were submitted to this rulemaking which relate to separately noticed

Cap-and-Trade program rulemakings, which is outside 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 the 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 #02, and it is comment #03 of the letter. The commenter abbreviation is SU. This abbreviation code would be B 02.03 – SU. All submitted written comments for the mandatory reporting rulemaking are available here:

http://www.arb.ca.gov/regact/2013/ghg2013/ghg2013.htm

Example: System Power Provision
Comment: Commenter requests the removal of the system power provision for electric power entities. [B 02.03 – SU]

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 #02 includes several comments, so within the responses, these individual comments are identified as 02.01, 02.02, 02.03, 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 October 25, 2013.
T	Comment numbers prefixed with “T” were public “Testimony” provided verbally at the Board hearing on October 25, 2013.
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

Comment Number	Abbreviation	Commenter
OP01	MSCG	Steve Huhman, Morgan Stanley Capital Group, Inc.
OP02	WPTF	Clare Briedenich, Western Power Trading Forum
OP03	EJG	John Nagle, E & J Gallo Winery
OP04	EJG	John Nagle, E & J Gallo Winery
OP05	TA	Braydon Boulanger, TransAlta
OP06	CWCCC	Sarah Deslauriers, CA Wastewater Climate Change Group
OP07	APC	Keith Adams, Air Products and Chemicals, Inc.
OP08	WSPA	Cathy Reheis-Boyd, Western States Petroleum Association
OP09	PG&E	Claire Halbrook, Pacific Gas and Electric
OP10	CC	Lloyd Avram, Chevron Corporation
OP11	JA/GS	Harry Singh, J. Aron & Co. / Goldman Sachs
OP12	SCPPA	Lily Mitchell, Southern California Public Power Authority
OP13	VC	Robert Ehlers, Valero Companies
OP14	VC	Robert Ehlers, Valero Companies
OP15	PC	Mary Weincke, PacifiCorp
OP16	Removed	Posted and deleted because it was duplicate or unrelated
OP17	PG	Kara Roeder, Proctor and Gamble
OP18	BPA	Courtney Olive, Bonneville Power Administration
OP19	SMUD	William Westerfield, Sacramento Municipal Utility District
OP20	APS	Justin Thompson, Arizona Public Service
OP21	SCE	Cathy Karlstad, Southern California Edison Company
OP22	VC	Robert Ehlers, Valero Companies
OP23	WSPA	Catherine Reheis-Boyd, Western States Petroleum Association
OP24	UAL	Robert Schlingman, United Airlines, Inc.

OP25	AEPCO	Kyle Danish, Arizona Electric Power Cooperative
OP26	PX	Nico van Aelstyn, Powerex
OP27	PGE	Elysia Treanor, Portland General Electric
OP28	IEP	Amber Reisenhuber, Independent Energy Producers Association
OP29	CCEEB	Robert Lucas, California Council for Environmental and Economic Balance
OP30	WPTF	Clare Breidenich, Western Power Trading Forum
OP31	MSR	Susie Berlin, MSR Public Power Agency
OP32	IWC	Ann Trowbridge, Inergy West Coast, LLC
OP33	TID	Dan Severson, Turlock Irrigation District
OP34	EPUC/CAC	Katy Rosenberg, EPUC/CAC
OP35	KO	Melinda Hicks, Kern Oil and Refining Co.
OP36	CLFP	John Larrea, CA League of Food Processors
B01	LADWP	Mark Sedlacek, LADWP
B02	SU	Tamara Rasberry, Sempra Utilities
B03	WPTF	Ellen Wolfe, WPTF
T01	SCPPA	Norman Pedersen, SCPPA
T02	PX	Nico Van Aelstyn, Beveridge & Diamond PC for Powerex
T03	CLFP	John Larrea, CA League of Food Processors
T04	TID	Brian Biering, Turlock Irrigation District
T05	LADWP	Cindy Parson, LADWP
T06	MSR	Susie Berlin, M-S-R Public Power Agency
T07	IEP	Steven Kelly, Independent Energy Producers
T08	SCE	Frank Harris, Southern California Edison
T09	AB	Elise Paeffgen, Alston & Bird, LLP
T10	WSPA	Michael Wang, Western States Petroleum Association
T11	SE	Graeme Martin, Shell Energy
T12	WPTF	Ellen Wolfe, Western Power Trading Forum
T13	CC	Steven Arita, Chevron Corporation
T14	SMUD	Tim Tutt, Sacramento Municipal Utility District
F01	IEP	Amber Reisenhuber, IEP

F02	FF	Dave Duke, Foster Farms
F03	IR	Laura Beane, Iberdrola Renewables
F04	TA	Braydon Boulanger, TransAlta
F05	PFI	Melissa Poole, Roll Law Group / Paramount Farms International
F06	NVE	Christine Klimek, NV Energy
F07	WPTF	Clare Breidenich, Western Power Trading Forum
F08	TID	Dan Severson, Turlock Irrigation District
F09	MSR	Susie Berlin, MSR Public Power Agency
F10	WSPA	Catherine Reheis-Boyd, Western States Petroleum Association
F11	MSCG	Steve Huhman, Morgan Stanley Capital Group, Inc.
F12	SCPPA	Lily Mitchell, Southern California Public Power Authority
F13	APC	Keith Adams, Air Products and Chemicals, Inc.
F14	IWC	Ann Trowbridge, Inergy West Coast, LLC
F15	CPN	Barbara McBride, Calpine Corporation
F16	BPA	Courtney Olive, Bonneville Power Administration
F17	SU	Tamara Rasberry, Sempra Utilities
F18	LADWP	Cindy Parson, LADWP
F19	PX	Nico Van Aelstyn, Beveridge & Diamond PC for Powerex

45-DAY COMMENTS

AND STAFF RESPONSES

A. Subarticle 1. Applicability, Definitions, and General Requirements

(§95100 – §95105)

§95101 – Applicability

A-1. Applicability, reporting threshold for Local Distribution Company (LDC)

Comment:

Lower threshold for LDC reporting end-user volume from 25,000 CO_2e to 10,000 CO_2e and require ARB ID of end-user facility. Lowering the threshold will not result in a more inclusive or accurate greenhouse gas (GHG) inventory. Data will be used as a double check to verify facilities are reporting accurate emissions and to determine if facilities are subject to mandatory or abbreviated reporting. Reporting of a facilities' data is done manually, and it is very time-consuming to enter a facilities' data into the reporting tool, which includes facility name, address, meter number, and amount of natural gas delivered. The lowered threshold will include many more facilities than those for which we currently report. If ARB decides to adopt the lower reporting threshold, then SoCalGas and SDG&E strongly recommend, for the sake of time efficiency and workload effectiveness, LDCs should be allowed to upload a spreadsheet with all of the required customer data instead of manual input.
[B 02.07 – SU]

Response: The purpose of the rule change requiring reporting of end-user gas deliveries ≥ 10,000 MT CO_2e is to provide data that enables ARB staff to calculate a highly accurate covered emissions value for each natural gas supplier. This data is considered to be extremely important for ensuring the accuracy of the covered emissions calculation. Therefore, ARB declines to remove the lower threshold reporting requirements. However, in response to the commenter's recommendation, ARB staff is making necessary changes to the California electronic Greenhouse Gas Reporting Tool (Cal-eGGRT or reporting tool) to allow the upload of spreadsheet data in order to reduce the reporting burden.

A-2. Clarify Reporting Responsibilities for Owners That Are Not Operators

Comment: Proposed section 95101(a)(3) provides that: If a facility operator determines their reporting applicability and responsibility on the basis of common ownership, the basis of reporting applicability and responsibility can only be changed to common control at the beginning of a compliance period. If a facility operator determines their reporting applicability and responsibility on the basis of common control, the basis of reporting applicability and responsibility can only be changed to common ownership at the beginning of a compliance period. These provisions do not apply if there is a legal change in facility ownership. If there is a change in facility ownership, the provisions of section 95103(n) apply.

This new provision appears to contemplate that an entity can determine its reporting responsibility based on either common ownership or common operational control of a facility. However, this is inconsistent with section 95101(a)(1), which provides that the reporting responsibility for facilities in California falls on the operator of the facility; for fuel and carbon dioxide, on the supplier; and for imported electricity, on the importer. This section, which is crucial for interpretation of the Regulation, does not mention ownership as a possible basis for reporting responsibility:

(a) General Applicability.

(1) This article applies to the following entities:
(A) Operators of facilities located in California with source categories listed below are subject to this article regardless of emissions level: …
(B) Operators of facilities located in California with source categories listed below, are subject to this article when stationary combustion and process emissions equal or exceed 10,000 metric tons CO2e for a calendar year: …
(C) Suppliers of fuels provided for consumption within California that are specified below in paragraph (c);
(D) Carbon dioxide suppliers as specified below in paragraph (c) …;
(E) Electric power entities as specified below in paragraph (d); and,
(F) Operators of petroleum and natural gas systems as specified below in paragraph (e). [emphasis added]

Nor does the related definition of “reporting entity” in section 95102(a)(408) mention ownership: “a facility operator, supplier, or electric power entity subject to the requirements of this article.”

An operator is defined in section 95102(a)(326) as “the entity, including an owner, having operational control of a facility.” The key part of the definition is the reference to operational control. It appears from the definition of “operational control” in section 95102(a)(325) that the intention is that at any one time, only one entity can have operational control of a particular facility. This is a desirable outcome, avoiding debate as to which entity is liable.

The owner of a facility may have operational control of the facility, or it may not; another entity may be appointed as the operator and have operational control. This is a question of fact in each case. (For example, SCPPA owns the Magnolia generating facility in Burbank, but the operator of the facility, and the entity that currently reports emissions from that facility, is Burbank Water and Power.) If a non-owner has operational control of a facility, the definition of “operator”, combined with the clear language of section

95101(a)(1) above, requires the operator to report the facility's emissions and prevents the owner from reporting the emissions instead.

It is unclear whether, by including proposed new section 95101(a)(3), the ARB intends to allow an entity that owns (but does not operate) a facility to assume the reporting responsibility in place of the operator. If that is the ARB's intention, it should be made very clear as reporting responsibility determines emissions liability. There should be no room for doubt as to which entity must report emissions and surrender allowances for a facility. If the ARB intends to give the owner of a facility the option to assume reporting responsibility, sections 95101(a)(1)(A), (B) and (F) should be amended to refer to "Operators or owners" and a similar change may need to be made to the definition of "reporting entity" in section 95102(a)(408). [OP 12.01 – SCPPA]

Response: ARB staff notes that the purpose of the regulatory modifications for section 95101(a)(3) is to ensure the facility boundary is reported consistently during a Cap-and-Trade program compliance period. The modifications do not alter the underlying responsibility of reporting by the entity with operational control. Moreover, staff has reviewed the definition of "operator" in the regulation, and believes additional clarification is not necessary. The definition of "operator" in section 95102(a) begins: "Operator means the entity, including an owner, having operational control of a facility..." This clearly includes "owners" as part of the definition of "operators," while ensuring that reporting must be conducted by the operator (which could be the owner in some instances). The regulatory edits proposed by the commenter are not necessary for clarifying the intent of this term.

A-3. Unintentional Inclusion of Fugitive and Vented Emissions for Water Treatment Plants

Comment: This language [to include vented and fugitive emissions in the applicability determination] unintentionally requires the estimation of fugitive carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) emissions from municipal wastewater treatment plants (WWTPs). Reporting of these constituents, especially fugitive N_2O, will significantly increase the number of WWTPs that will no longer qualify for the abbreviated reporting allowed by being under the 25,000 metric ton CO_2e emissions threshold, and could also bring many municipal WWTPs into the Cap-and-Trade program. CWCCG recommends the following two amendments to resolve this issue: First, ARB should write in an explicit exclusion into §95101(f)(7) for "fugitive and process emissions of CH_4 and N_2O from municipal WWTPs; Second, ARB should reinsert language into §95852.2 of the Cap-and-Trade Regulation excluding "fugitive and process emissions of CH_4 and N_2O from municipal WWTPs" from a compliance obligation. [OP 06.01 – CWCCG]

Response: The reporting regulation does not have a specific reporting sector for nor does it refer to a U.S. EPA subpart related to municipal waste water facilities. Some municipal waste water facilities may be subject to the reporting regulation, but only as sources of CO_2 and methane emissions from combustion of methane gas, not fugitive CH_4 and N_2O. Even in those instances where a municipal waste water facility reports to ARB, the reporting regulation does not require municipal waste water facilities to estimate and report fugitive N_2O emissions since there is no specific requirement to report these as process emissions. Additionally, the reporting regulation does not have an N_2O emission estimation method to estimate these fugitive emissions from municipal waste water facilities. Moreover, since this data is not required to be reported, it will not be included in the reporting tool, and per section 95104(e), municipal waste water facilities would not need to report data not specified in the reporting tool. As this response relates solely to those aspects of the comment addressing modifications to the reporting regulation through this rulemaking, ARB staff declines to comment on the portions of the comment addressing the separate Cap-and-Trade Regulation rulemaking.

§95102 - Definitions

A-4. Definition for Pipeline Quality Natural Gas

Comment:

Pipeline Quality Natural Gas Definition - §95102(a)

SoCalGas and SDG&E have previously provided written comments regarding the definition of "Pipeline Quality Natural Gas" and its application within the regulation. While some of our concerns have been addressed, issues remain that we feel require additional consideration.

In MRR Section 95102, Definitions, the use of the word *quality* in the definition of "Pipeline Quality Natural Gas" is used to define a default range for energy content (British thermal Unit – BTU), which determines the methodology for MRR emissions calculation. SoCalGas and SDG&E request the word *quality* be eliminated from the definition of pipeline natural gas to avoid the issues discussed below. Such a change would not affect the meaning or function of the term within the MRR.

SoCalGas and SDG&E request the removal of the word *quality* because it implies a standard or grade having an intrinsic value, characteristic or feature. The word *quality* often implies excellence or grade and conveys a positive connotation, whereas anything not labeled with the word *quality* creates a negative connotation. The use of the word *quality* in the definition of pipeline natural gas may create concern for natural gas customers whose purchased natural gas falls outside of the specified default range in the MRR definition. Because of the MRR definition's implication of *quality*, a customer may think their purchased gas is not *quality* natural gas, despite the fact it meets the California Public Utility Commission's (CPUC) natural gas specifications.

(continued on next page)

The CPUC establishes natural gas specifications to which California's utilities must adhere for purposes of receiving, transporting, and delivering natural gas to their customers. Because the CPUC has overall State jurisdiction over natural-gas quality issues, ARB should remove the word *quality* from the definition of pipeline natural gas or choose a different term to define the default range for calculation purposes under MRR to avoid the impression that ARB is asserting authority over the CPUC on natural gas quality issues.

Additionally, SoCalGas and SDG&E remain concerned that the definition of pipeline natural gas states that *pipeline quality natural gas* contains at least *ninety percent* methane by volume, and request that this be changed to align with the CPUC specification for methane content. The CPUC has exclusive jurisdiction over the quality and composition of natural gas delivered to utility customers in California. The methane content of at least *ninety percent* methane by volume is in conflict with CPUC's gas specifications that state pipeline natural gas be at least *eighty percent* methane by volume. While the CPUC requires natural gas utilities to provide the BTU content of customer's purchased gas, there is not a similar requirement for methane content. Further, we understand that the methane content portion of the definition for pipeline natural gas originated with the federal Environmental Protection Agency (USEPA). USEPA wrote this definition decades ago and it has not been changed to take into account the fact that our nation's domestic natural gas production, especially California production, may have lower methane content than ninety percent by volume but a higher overall energy content. We believe that the at least ninety percent methane content in the MRR definition of pipeline natural gas has an insignificant effect on the statewide greenhouse gas (GHG) emission inventory, especially considering that methane has a higher GHG warming potential than the carbon dioxide produced from combustion of natural gas. Thus, lower methane content gas may produce overall lower GHGs than gas with a higher methane content.

SoCalGas and SDG&E urge ARB to make the suggested changes below (shown in red highlight and strikeout) to the definitions in the MRR amendments.

Suggested Language Modifications

Section 95102(a)(296) "Natural gas" means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include methane, heavier hydrocarbons and carbon dioxide. Natural gas may be for field use ~~quality (which varies widely)~~ or pipeline ~~quality~~ natural gas. For the purposes of this article, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

Section 95102(a)(338) "Pipeline ~~quality~~ natural gas" means, for the purpose of calculating emissions under this article, natural gas meeting specifications for natural gas ~~having a high heat value~~ as defined by the California Public Utilities Commission (CPUC). ~~greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, and which is at least ninety percent methane by volume, and which is less than five percent carbon dioxide by volume.~~

Section 95102(a)(464) "Transmission pipeline" means a high pressure cross country pipeline transporting sellable ~~quality~~ natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

[B 02.01 – SU]

Response: Staff has not proposed any amendments to the definitions for "natural gas," "pipeline quality natural gas," or "transmission pipeline." As such, the commenter's requested changes are beyond the scope of the current rulemaking. Notwithstanding this, ARB staff notes that the commenter is correct that ARB aligned the definition for "pipeline quality natural gas" with the definition used by U.S. EPA. The definition is intended to set the bounds for MMBtu and methane content for which the default emissions factor is applicable. Natural gas outside of these specifications must use alternative emissions factors or quantification methods for determining CO_2 emissions from combustion. At this time, in addition to being outside the scope of the current rulemaking, ARB staff does not believe any of the changes proposed by the commenter are appropriate and declines to make these changes. ARB is open to re-visiting the composition of pipeline quality gas in future regulatory updates if data are provided that demonstrate one or more of the specifications in the regulation is not needed to ensure estimation of CO_2.

A-5. Clarify Intrastate Pipeline Definition

Comment: The proposed amendment includes the following definition for intrastate pipeline:

(254) “Intrastate pipeline” means any pipeline or piping system wholly within the state of California that is delivering natural gas to end-users and is not regulated as a public utility gas corporation by the California Public Utility Commission (CPUC), not a publicly-owned natural gas utility and is not regulated as an interstate pipeline by the Federal Energy Regulatory Commission. For purposes of this article, intrastate pipeline operators that physically deliver gas to end users in California are considered to be Local Distribution Companies [LDC]. Facilities that receive gas from an upstream LDC and redeliver a portion of the gas to one or more adjacent facilities are not considered intrastate pipelines.”

Our understanding is that a facility which receives gas from an upstream LDC and redistributes the gas to downstream facilities is not an intrastate pipeline. However, it is not clear whether a pipeline is an intrastate pipeline in the following situations:

a) The facility processes or mixes gas received from an upstream LDC with other gases and redistributes the processed gas
b) Total gas redistributed a greater amount of gas than the amount that was received
c) The gas received or redistributed is part of a gas exchange

Recommendation:
WSPA recommends ARB clarify the above questions in the regulation or provide a guidance document for reporters. [OP 08.03 – WSPA]

Response: ARB staff believes the existing definition of “intrastate pipeline” is sufficient to answer the questions from the commenter. To the extent necessary, ARB staff will work with stakeholders and, if necessary, provide guidance for intrastate pipeline reporting in cases where entities are unsure of the required reporting rules for a specific operational scenario. This includes the three scenarios listed in comment regarding mixed gas, a greater amount of gas is redistributed than was received and gas exchanges.

A-6. Revise Definition of Position Holder

Comment:

Determination of Position Holder (pg. 67)

In section 95121(a)(2) of the Proposed Order, there are no revisions to the definition of 'position holder' or 'title holder' that reflect the guidance released in April 2013 clarifying the reporting requirements for position holders of transportation fuels that are subject to the Cap & Trade provisions. The regulation and the guidance hinge upon the determination of 'position holder' or 'title holder,' both of which are key for determining the entity responsible for reporting the emissions from the combustion of transportation fuels starting in the second compliance period.

Earlier in 2013, Valero had several discussions with CARB by telephone and in person to confirm that Valero's interpretation of the MRR Rule is commensurate with CARB's reporting requirements. Valero also submitted a letter to CARB explaining its understanding of Section 95121(d) and CARB's explanatiopn of that provision. CARB in person (MRR Dept.) and by its guidance document confirmed Valero's interpretation, and Valero submitted its transportation fuels data for 2012 using Board of Equalization data, which is based on excise tax rules. While CARB's acceptance of that report further confirms Valero' interpretation, Valero would like to be on record as requesting that the regulation explicitly clarify the basis of determining the responsible party for reporting transportation fuels under the cap.

Valero requests that the rule include the Board of Equalization (IRS Excise Tax rules) definitions for the determination of position holder. CARB could also use language from its guidance document from April 2013. Valero suggests the following addition (underlined) to the current definition:

> (346) "Position holder" means an entity that holds an inventory position in motor vehicle fuel, ethanol, distillate fuel, biodiesel, or renewable diesel as reflected in the records of the terminal operator or a terminal operator that owns motor vehicle fuel or diesel fuel in its terminal. "Position holder" does not include inventory held outside of a terminal, fuel jobbers (unless directly holding inventory at the terminal), retail establishments, or other fuel suppliers not holding inventory at a fuel terminal. The status of 'position holder' can be determined by running a Board of Equalization report for excise tax purposes.

[OP 13.01 – VC]

Response: The commenter is correct that staff did not propose any changes to the definition of "position holder" in this rulemaking. As such, the requested changes are beyond the scope of this rulemaking. Notwithstanding this, ARB staff notes that the intent of the definition of position holder is to align with the definition used by the Board of Equalization (BOE) for tax reporting purposes. However, and given that the comment is beyond the scope of this rulemaking, ARB staff does not believe the change suggested by the commenter is needed because ARB does not want to solely rely on BOE excise tax reports alone for determination of position holder status.

A-7. Modify Definition of Onshore Petroleum and Natural Gas Production Facility

Comment: The proposed amendment includes the following definition for onshore petroleum and natural gas production facility.

(326) “Onshore petroleum and natural gas production facility” means all petroleum or natural gas equipment on a well pad, or associated with a well pad or to which emulsion is transferred and CO2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator that are located in a single hydrocarbon basin as defined in 40 CFR §98.238. When a commonly owned cogeneration plant is within the basin, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant. Where a person or operating entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Based on CARB facility guidance document (http://www.arb.ca.gov/cc/reporting/ghg-rep/guidance/ghg_oilgasfacility_definition.pdf, dated 2/29/12, page 3) for Petroleum and Natural Gas Systems, the “associated with” term is also inclusive of cogeneration facilities that supply steam and/or electricity to the well pad.

Cogeneration units located in the basin are included in the Onshore Production facility only if these units supply steam and electricity to the well pads. This guidance is consistent with EPA’s guidance on facility determination of industry segments. However, the text added to the existing definition requires cogeneration plants located in the basin to be included in the Onshore Production facility regardless of the industry segment that the units serve. Was this CARB’s intention and if so, will the guidance document change to reflect that? In addition, should the reporters re-assign cogeneration plants to facilities based on the above definition for the 2013 report?

Recommendation:
WSPA recommends ARB revise the statement added to the definition as shown in red font below:

When a commonly owned cogeneration plant is within the basin and serves well pad operations, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant. [OP 08.04 – WSPA]

Response: In this comment, WSPA proposes to clarify the definition of onshore petroleum and natural gas production facility by including language regarding the well pad. Staff believes this change is not necessary because, by definition, the onshore facility must include all equipment that is associated with the well pad in its facility boundary. This includes cogeneration facilities that are used to support the well pad. The facility boundary should not include cogeneration plants that do not support well pad operations, consistent with the existing definitions. As stated by the commenter, reporters should not re-assign cogeneration plants that are not associated with the well pad, but in the basin for 2013 data reported in 2014. ARB staff declines to make the requested change.

A-8. Revise Definition of Conventional Wells

Comment: The proposed amendment includes the following definitions for conventional and unconventional wells: (105) "Conventional wells" mean crude oil or gas wells in producing fields that do not employ hydraulic fracturing to produce commercially viable quantities of natural gas.

(481) "Unconventional wells" means crude oil or gas wells in producing fields that employ hydraulic fracturing to enhance crude oil or gas production volumes.

Recommendation:
We recommend the definition of conventional wells be changed (as indicated in the red font below) to the following to align with the definition of "unconventional wells" as follows: (105) "Conventional wells" mean crude oil or gas wells in producing fields that do not employ hydraulic fracturing to produce commercially viable quantities of crude oil or natural gas. [OP 08.02 – WSPA]

Response: Staff agrees with this comment and included the change as part of the 15-day modifications.

A-9. Natural Gas Liquids Definitions

Comment:

Inergy's comments follow-up on prior comments regarding the definition of "product" and related terms. As a natural gas liquids processor, Inergy continues to recommend that "product," "product output," "production" and related terms be clearly defined to ensure that natural gas processing operations have reasonable certainty as to how the Cap-and-Trade Regulation and MRR may apply to them and that they are equitably treated under those regulations. While the proposed revisions to the Cap-and-Trade Regulation, including the proposed modifications to the benchmark for natural gas processing facilities, begin to address some of Inergy's concerns, additional revisions are needed to both the Cap-and-Trade Regulation and the MRR to clearly specify what "product," "product output," and "production" and related terms mean for purposes of reporting and allowance calculations.
[OP 32.01 – IWC]

Response: The comment does not suggest any specific modifications to these definitions, but ARB staff believes the definitions as proposed provide the necessary clarity to ensure reporting entities understand their reporting obligations. Consistent with existing practice, however, ARB staff will continue to work with stakeholders to ensure successful program implementation and may provide further assistance through written guidance if necessary. With respect to the Cap-and-Trade program, it is ultimately up to the Cap-and-Trade Regulation to define how "product output"/"production" are used for determining allowance allocations.

A-10. Asset Controlling Supplier, Section 95102(a)(20).

Comment: To maintain alignment with the dual requirement of a written power contract and direct delivery, and consistency with the proposed new MRR § 95111(a)(5)(E), Powerex respectfully submits that the asset controlling supplier definition should be clarified to refer to the system of an ACS entity, as shown here:

> **§95102(20)** "Asset-controlling supplier" means any entity that owns or operates inter-connected electricity generating facilities or serves as an exclusive marketer for these facilities even though it does not own them, and is assigned a supplier-specific identification number and system emission factor by ARB for the wholesale electricity procured from its system and imported into California. **An** Asset-controlling supplier's system is ~~are~~ considered a specified source~~s~~.

[OP 26.02 – PX]

Response: While ARB staff understands the commenter's intent for suggesting this change to the definition of "asset-controlling supplier (ACS)," staff believes that the suggested changes are unnecessary because the commenter's modifications are already implied in the definition of "asset controlling supplier" and other references to the use of the term ACS in section 95111. Moreover, ARB staff notes that the definition of "specified source" already states that "Specified source also means electricity procured from an asset-controlling supplier recognized by ARB."

A-11. Direct Delivery, Section 95102(a)(25).

Comment: Section 95852(b)(3)(C) of the cap-and-trade regulation further clarifies that in order to claim a specified source, "[t]he electricity must be directly delivered, as defined in MRR section 95102(a), to the California grid." And the MRR's applicable definition of "direct delivery of electricity" in MRR § 95102(25)(C) is unambiguous:

"Direct delivery of electricity" or "directly delivered" means electricity that … is scheduled for delivery from the specified source into a California balancing authority via a continuous physical transmission path from interconnection of the facility in the balancing authority in which the facility is located to a sink located in the state of California. …

The responsibility to provide evidence of direct delivery via a continuous transmission path is not reconcilable with an interpretation of an ACS entity as itself a specified source. Powerex is an ACS entity, but it is not itself a source in a general sense nor a "generation source" as that term is defined in MRR § 95102(431). Powerex itself is not dispatched, does not generate, and is not scheduled. Instead, Powerex acts as the exclusive marketer for BC Hydro's facilities, and also markets energy from a variety of other "generation sources" outside of British Columbia. [OP 26.03 – PX]

Response: The comment from Powerex on this topic is appreciated; however, ARB staff disagrees with this interpretation. The responsibility to provide evidence of direct delivery via a continuous transmission path is, in fact, reconcilable with an interpretation of an ACS entity as itself a specified source. Continuous transmission can be demonstrated using the physical path table of the NERC e-tag, where the ACS entity is listed in the first data line of the physical path table as the purchasing-selling entity (PSE), and as the source in the Point of Receipt/Point of Delivery (POR/POD) field. For ACS entities that are exclusive marketers, the first data line of the physical path table would reflect the upstream entity, and its generating facility or group of generating facilities, on behalf of whom the ACS is the exclusive marketer, namely, the purchasing-selling entity (PSE) field and the source in the POR/POD field. This is evidence of direct delivery for ACS power, notwithstanding any further refinements or clarifications. ARB staff therefore is not making any changes based on the comment.

A-12. Electricity Importers definition on the issue of Reverse Wheels, Section 95102(a)(140)

Comment: PG&E believes ARB does not intend energy sourced inside of California, wheeled out, and then back into the state to be included in import calculations as this would qualify as "double counting." This generation should already be reported by the in-state generating facility. However, the current MRR language does not mention the e-Tag's origin which may lead entities to report these trades as imports with an associated GHG obligation. To remedy this issue, PG&E recommends the following modification to the definition of "electricity importers" in Section 95102(a)(141):

For electricity that is scheduled with a NERC e-Tag that has a first point of receipt outside the state of California to a final point of delivery inside the state of California. [OP 09.09 – PG&E]

Response: Staff agrees with the concern raised by PG&E with the understanding that this pertains to cases of one transaction on one NERC e-tag. Energy sourced inside of California, wheeled out, and then back into California on one e-tag should not be considered an import, as this would qualify as "double counting." More precisely, energy that sources and sinks in California on one e-tag, even if wheeled outside the state and back, is not an import and should be considered in-state generation. ARB staff believes that the current regulatory language already specifies this is how such energy on one e-tag must be reported, and therefore declines to make the suggested change.

A-13. Electricity Importers definition on Energy Imbalance Market issues, Section 95102(a)(140).

Comment: The CAISO is in the process of modifying and extending its existing real-time energy market systems to provide EIM service to PacifiCorp and its transmission customers. The EIM will be a voluntary market for procuring imbalance energy to balance supply and demand deviations from forward energy schedules through a 15-minute market and five minute dispatch in the combined network of ISO and EIM Entities. Because the EIM will be dispatched in the combined network of the ISO and EIM Entities, imbalance energy is expected to be imported into California at times and exported out of California at times. PacifiCorp expects the imports into California will trigger a compliance obligation under the MRR and Cap-and-Trade Program for resources participating in EIM. Accordingly, the proposed revisions to the MRR and Cap-and-Trade Program include revisions to the definitions of Electricity Importer and Imported Electricity to account for energy imported into California as a result of EIM.

In general, PacifiCorp is supportive of the proposed modifications to accommodate the ISO's EIM proposal. However, PacifiCorp provides the below suggested modifications to the definitions to further increase clarity and consistency with the ISO's EIM proposal: As proposed, the definition of Electricity Importers will be revised to include:

EIM Participating Resource Scheduling Coordinators serving the EIM market whose transactions result in electricity imports into California.

PacifiCorp proposes the following revisions:

> EIM Participating Resource Scheduling Coordinators which facilitate dispatch EIM Participating Resources which ~~serving the EIM market whose transactions~~ result in electricity imports into California.

This revision is proposed to ensure consistency with the current version of the ISO's EIM proposal, in which "EIM Participating Resource Scheduling Coordinator" and "EIM Participating Resource" are distinct terms and may be distinct entities. While an EIM Participating Resource may choose to also be the EIM Participating Resource Scheduling Coordinator for purposes of dispatching resources in the EIM, an EIM Participating Resource may also choose to engage another entity to be its Scheduling Coordinator. Also, technically the EIM Participating Resources are dispatched while the EIM Participating Resource Scheduling Coordinators facilitate that dispatch. The proposed modification clarifies these distinctions. [OP 15.05 – PC]

Response: ARB appreciates the comment and explanation provided by PacifiCorp, however, we decline to make the requested change as the current language is sufficient given that the EIM market design has not been finalized through FERC approval. ARB staff believes the proposed language provides implementation flexibility for when the EIM market design is finalized.

A-14a. Energy Imbalance Market, Section 95102(a)(151)

Comment: SCE appreciates that the Proposed Amendments related to the Energy Imbalance Market ("EIM") are broad enough to accommodate some potential modifications to the California Independent System Operator's ("CAISO's") proposed EIM design. However, there are still many EIM-related issues and processes that could considerably alter the EIM design before the Federal Energy Regulatory Commission ("FERC") approves a final EIM design. The ARB should be aware that its EIM-related language might require future alteration depending on the outcome of the EIM proposal approval process.
[OP 21.05 — SCE]

A-14b. Energy Imbalance Market, Section 95102(a)(151)

Comment: During the Board meeting, SCE orally reiterated these concerns.
[T 08.02 — SCE]

Response: (this response effective for comments A -14, a-b above).
ARB staff is aware that the EIM-related language could possibly require future alteration depending on the outcome of the EIM review process at FERC. However, ARB staff considers the EIM-related language for 2014 to be reasonable based on a review of stakeholder comments and ARB staff consultation with CAISO staff. In the event significant changes to the EIM market design are required by FERC, ARB staff has the option to consider the issuance of explanatory guidance or to address necessary modifications in future rulemakings.

A-15. First Point of Receipt, Section 95102(a)(179)

Comment: §95102 (179) Definition of First Point of Receipt: additional clarification is needed to address cases where the generating facility and first point of receipt are located in different states. ARB is proposing to amend the definition of "First Point of Receipt" to clarify that for GHG reporting purposes, the *"First Point of Receipt" means the location from which a Generator delivers its output to the transmission system (the closest POR to the generation source).*

LADWP recommends an additional clarification to the definition of "First Point of Receipt" to address cases where the generating facility and the first point of receipt on the North American Electric Reliability Corporation (NERC) E-tag are located in different states. For example, Hoover Power Plant is physically located on the state line between

Nevada and Arizona, but the first point of receipt is Mead, located in Nevada. In cases where a generating facility located just inside the California border is within the boundaries of an out-of-state balancing authority area, the NERC E-tag may show a first point of receipt located in Arizona, Nevada or Oregon. If electricity from that generating facility is ultimately consumed in California, the definition of Imported Electricity states that energy that is generated and consumed in California is not an import. However, since the first point of receipt is the basis for aggregating and reporting unspecified imports and exports, and the first point of receipt on the E-tag is located outside of California, this would look like an import. As a result, an E-tag with the generation source and load (sink) located inside California and the first point of receipt located outside California could mistakenly be reported as an unspecified import.

To address this, LADWP recommends adding the following sentence to the definition of "First Point of Receipt":

In cases where the generation source and the first point of receipt are not located within the same geographic jurisdiction relative to the physical boundaries of California, the first point of receipt is the location of the generating facility or unit.

This addition would clarify what jurisdiction should be used as the origin of the energy when determining whether the energy is imported or exported in cases where the generation source and the first point of receipt are located in different states. LADWP recommends adding this new sentence to the definition of "First Point of Receipt" as follows:

(~~176~~179) "First point of receipt" means the location from which a Generator delivers its output to the transmission system (the closest POR to the generation source) ~~generation source specified on the NERC e-Tag~~, where defined points have been established through the NERC Registry. *In cases where the generation source and the first point of receipt are not located within the same geographic jurisdiction relative to the physical boundaries of California, the first point of receipt is the location of the generating facility or unit.* 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. [B 01.01 — LADWP]

Response: After reviewing stakeholder comments, ARB staff has withdrawn the proposed changes to this definition in the 15-day changes. Reverting to the definition which is currently in effect ensures consistency in reporting between 2012 and 2013 data. The specific change proposed by LADWP is somewhat specific to its own system, and ARB staff does not believe such a change is needed given that the definition will ultimately remain the same as what is currently in effect.

A-16. Generation Providing Entity or GPE, Section 95102(a)(216)

Comment: WPTF requests that ARB modify the definition of GPE in Section 95102(a)(216) so that it correctly refers to those categories of entities with rights to *market* the electricity from a facility or unit (i.e. owners, toll holders and exclusive marketers). WPTF also suggests deleting the phrases “that is either the electricity importer or exporter” and “specified source” because they are unnecessary and addressed elsewhere—section 95111(a) requires GPEs that are importers and exporters to report associated power as specified and the definition of specified source establishes when electricity from a facility or unit is specified. WPTF proposed the following edits:

(216) “Generation providing entity” or “GPE” means an entity with ~~facility or generating unit operator,~~ full or partial ownership of a generating facility or unit, ~~party to a contract for a fixed percentage of net generation from the facility or generating unit,~~ 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~~ sell electricity from the facility or unit or system. ~~specified source~~.
[OP 02.02 – WPTF]

Response: The definition of “generation providing entity” was not modified in the 45-day regulatory amendments. As such, the comment is beyond the scope of this rulemaking. However, ARB staff believes the existing definition already conveys the meaning sought by the commenter. ARB staff further notes that the definition of “specified source,” which was also not modified in the 45-day regulatory amendments, is already clear as to what constitutes a “specified source,” and that the GPE and “specified source” definitions are consistent in their meaning and application. As such, ARB declines to make the changes proposed by the commenter.

A-17a. Imported Electricity on the issue of Emergency Assistance, Section 95102(a)(245)

Comment: SCPPA states that the MRR regulation does not define "Independent System Operator" and that the term appears to refer to the California Independent System Operator ("CAISO"). However, the relevant North American Electric Reliability Corporation ("NERC") standard, Standard EOP-002 – Capacity and Energy Emergencies, applies not just to the CAISO but more generally to balancing authorities and reliability coordinators. CAISO is an important, but not the only, balancing authority in California. Other balancing authorities (including some of the SCPPA members) that are not known as "Independent System Operators" may also be required to import electricity for reliability purposes under NERC Standard EOP-002 from time to time. Therefore, the definition of "Imported Electricity" should refer to balancing authorities rather than just "Independent System Operators" in the sentence on emergency assistance.

Furthermore, the term "balancing authority" is defined in section 95102(a)(25). To avoid inadvertently restricting the application of the first new sentence in the definition of "Imported Electricity" and to maintain consistency with existing defined terms, section 95102(a)(245) should be revised as set out below:

(245) "Imported Electricity" means electricity generated outside the state of California and delivered to serve load located inside the state of California. ... Imported Electricity does not include electricity imported into California by a~~n~~ balancing authority ~~Independent System Operator~~ to obtain or provide emergency assistance under applicable emergency preparedness and operations reliability standards of the North American Electric Reliability Corporation or Western Electricity Coordinating Council.

According to SCPPA, the above change should be made to the definition of "Imported Electricity" in the cap-and-trade regulation. [OP 12.02 – SCPPA]

A-17b. Imported Electricity on the issue of Emergency Assistance, Section 95102(a)(245)

Comment: LADWP. §95102(a)(245) Definition of Imported Electricity: emergency assistance provision should apply to all California balancing authorities. ARB is proposing to add the following sentence to the definition of "Imported Electricity":

Imported Electricity does not include electricity imported into California by an Independent System Operator to obtain or provide emergency assistance under applicable emergency preparedness and operations reliability standards of the North American Reliability Corporation or Western Electricity Coordinating Council.

It appears that "Independent System Operator" refers to the California Independent System Operator (CAISO). The Initial Statement of Reasons (ISOR) for the proposed amendments to the MRR states that this amendment is necessary to exclude electricity imported into California to meet emergency assistance requirements. Although the

CAISO is a large balancing authority in California, there are a number of other balancing authorities in California including the Los Angeles Department of Water and Power (also known as LDWP) that are also subject to the emergency preparedness and operations reliability standards of the NERC and the Western Electricity Coordinating Council (WECC). (See NERC Reliability Standard EOP-002-3 and WECC Reliability Coordinator responsibilities in RC EOP-002).

Balancing authorities are responsible for maintaining load-interchange-generation balance within their respective balancing authority areas and supporting interconnection frequency in real time. The NERC standards specify that in the event of an emergency, neighboring balancing authorities should be contacted to provide assistance. LADWP has provided emergency assistance in the past, and could be required to import energy into California to provide emergency assistance to a neighboring balancing authority in the future.

Since all balancing authorities have the same responsibilities, the proposed amendment to the definition of "Imported Electricity" for electricity imported into California to obtain or provide emergency assistance under NERC or WECC emergency preparedness and operations reliability standards should apply to all balancing authorities, not just to the CAISO. To ensure equitable treatment of all balancing authorities, the proposed amendment should apply to a "Balancing Authority" rather than "an Independent System Operator". Balancing Authority is already a defined term in the regulation, whereas Independent System Operator is not a defined term.

LADWP recommends substituting "a Balancing Authority" in place of "an Independent System Operator" in the definition of "Imported Electricity" as shown below:

(~~240~~245) "Imported electricity" means electricity generated outside the state of California and delivered to serve load located inside the state of California. Imported electricity includes electricity delivered across balancing authority areas from a first point of receipt located outside the state of California, to the first point of delivery located inside the state of California, having a final point of delivery in California. Imported electricity includes electricity imported into California over a multi-jurisdictional retail provider's transmission and distribution system, or electricity imported into the state of California from a facility or unit physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission and distribution system. Imported electricity includes electricity that is a result of cogeneration located outside the state of California. Imported electricity does not include electricity wheeled through California, defined pursuant to this section. Imported electricity does not include electricity imported into the California Independent System Operator (CAISO) balancing authority area to serve retail customers that are located within the CAISO balancing authority area, but outside the state of California. Imported Electricity does not include electricity imported into California by ~~*an Independent System Operator*~~ *a Balancing Authority* to obtain or provide emergency assistance under applicable emergency preparedness and operations reliability standards of the North American Electric Reliability Corporation or Western Electricity Coordinating Council. Imported electricity shall include Energy Imbalance Market dispatches designated by the CAISO's optimization model and reported by the CAISO to EIM Participating Resource Scheduling Coordinators as electricity imported to serve retail customers load that are located [B 01.02 – LADWP]

Response: (this response effective for comments A-17 a-b above).
ARB adopted regulations for mandatory reporting and to implement a Cap-and-Trade program that apply to large emitters of greenhouse gases, including electricity importers. The CAISO is not considered an electricity importer under the Cap-and-Trade regulation. As background, the mandatory reporting and Cap-and-Trade regulations define an electricity importer as the entity identified on the North American Electric Reliability Corporation (NERC) e-Tag as the purchasing-selling entity (PSE) on the last segment of NERC e-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. As ARB explained in its final statement of reasons submitted to the Office of Administrative Law supporting its Cap-and-Trade regulation, CAISO is not registered as a PSE, and therefore CAISO does not meet the definition of an electricity importer. However, in order to support some interchange transactions involving emergency assistance between balancing authority areas CAISO may, from time-to-time, be identified on a NERC e-Tag as a PSE. ARB staff understands that this would be a rare occurrence, and that CAISO is willing to provide ARB staff with aggregated information concerning interchange transactions for emergency assistance on an annual basis.

Under these circumstances, CAISO merely facilitates the delivery of electricity and is not an electricity importer for purposes of the greenhouse gas mandatory reporting or Cap-and-Trade regulations. The purpose of the language proposed by ARB staff is to clarify that these regulations do not apply to CAISO under these rare circumstances. Aggregated information provided by CAISO will be used by ARB staff to monitor the frequency of these conditions and the amount of power involved to ensure these circumstances continue to be consistent with the goals of Assembly Bill 32.

Based upon the above explanation, ARB staff does not agree with the commenter that a definition is needed for CAISO nor that an emergency power exemption for the other balancing areas in the state is necessary.

A-18. Imported Electricity on Energy Imbalance Market issues, Section 95102(a)(240)

Comment: PacifiCorp recommends the following change to the definition of Imported Electricity:

> Energy Imbalance Market (EIM) dispatches ~~designated~~ instructed by the CAISO's EIM market operator ~~optimization model~~ and reported by the CAISO to EIM Participating Resources Scheduling Coordinators as electricity imported in~~to serve retail customers load that is located within the State of~~ California.

This revision is proposed to provide a simplification and clarification of the proposed language. In the EIM proposal, the terms “EIM dispatches” and “designated” are not used in the manner currently proposed in the revised definition of Imported Electricity. The ISO market operator instructs the dispatch of EIM Participating Resources. In addition, according to the way the optimization model is designed, the ISO market operator will only identify and report electricity imported into California where California is the final destination – it will not identify energy wheeled through California. Therefore the language “to serve retail customer load located within the State of California” is superfluous. [OP 15.06 – PC]

Response: Please see response to comment A-14a-b [OP 21.05].

A-19a Power Contract, Section 95102(a)(356)

Comment: WPTF requests that ARB modify the definition of “power contract in section 95102(a)(356) to require both the designation of a facility and clear intention of the seller to transact that power as specified. This could be demonstrated via a seller warranty of the sale of specified power, as required under section 95111(a)(4), or through other means, such as the conveyance of environmental attributes. WPTF proposed the following edits:

(356) “Power contract” or “written power contract,” as used for the purposes of documenting specified versus unspecified sources of imported and exported electricity, means a written document, including associated verbal or electronic records if included as part of the written power contract, arranging for the procurement of electricity. Power contracts may be, but are not limited to, power purchase agreements, enabling agreements, electricity transactions, applicable international treaties, 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. A power contract for a specified source is a contract that is contingent upon delivery of power from a particular facility, unit, system, or asset-controlling supplier’s system that is designated at the time the transaction is executed and in which the seller warrants, or otherwise clearly indicates, that the transaction is for specified source electricity. [OP 02.04 – WPTF]

A-19b Power Contract, Section 95102(a)(356)

Comment: Powerex. Changes Are Needed to Align the Definitions of “Specified Source” and “Asset Controlling Supplier” with the Definitions of “Power Contract” and “Direct Delivery” and also ARB’s Proposal Regarding “Tagging ACS Power.”

Within the MRR, references vary between transactions with an ACS and the system of the ACS. Powerex believes that the interpretation of the ACS *as* a generation source is not reconcilable with industry scheduling practices and the bulk of the MRR which treat an ACS as an owner or marketer. ARB should align the definitions of ”specified source” and ”asset controlling supplier” with the rest of the Regulation, which recognizes that it is the *system of an ACS* that may be designated as a specified source, and not the ACS entity in and of itself. The definition of “power contract” in MRR § 95102(351) makes the issue clear (emphasis added):

“Power contract” or “written power contract,” as used for the purposes of documenting specified versus unspecified sources of imported and exported electricity, …. 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.

The definition specifically references the “system” of an asset controlling supplier (*i.e.*, the “inter-connected electricity generating facilities” that the ACS registered in its ACS application.)

Powerex believes that it is important to further strengthen and clarify the definition of “written power contract” to require *actual* written contracts such that ambiguous verbal communications cannot be mistaken for a representation that power is specified. By requiring written documentation that both buyer and seller agree upon, the intentions of all parties to a power transaction are clarified and documented. This addition to the proposed seller representations will ensure that all participants in the power markets know what they are buying and selling, all such transactions can later be audited and verified if necessary, and by applying this requirement upon importers of specified power when they file their reports with ARB, ARB will be able to clarify the integrity of the contractual chain without regulating out-of-state entities.

To achieve this, we propose a few simple modifications to the definition of “power contracts” in MRR Section 95102(a)(356):

> "Power contract" or "written power contract," as used for the purposes of documenting specified versus unspecified sources of imported and exported electricity, means a written document~~, including associated verbal or electronic records if included as part of the written power contract,~~ arranging for the procurement of electricity. Power contracts may be, but are not limited to, power purchase agreements, enabling agreements, electricity transactions, applicable international treaties, 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. **For specified power contracts, other forms of contracting, including the use of associated electronic and verbal records generated under an enabling agreement, will meet the requirements of this definition, provided that the underlying written agreement includes express contractual terms regarding specified power.** A power contract for a specified source is a **written** contract that is contingent upon delivery of power from a particular facility, unit, system or asset-controlling supplier's system that is designated at the time the transaction is executed.

Powerex appreciates that long term legacy contracts may not have been sufficiently clear in their contracting and agrees that contracting parties and verifiers may need to make some interpretations for historic contracts. Powerex strongly believes that this form of contracting provides value to importer and generator alike by making the intentions of all parties clear.

For all the reasons set forth above, and touched upon below as well, we therefore call upon ARB to require actual *written* power contracts. [OP 26.04 – PX]

Response: (this response effective for comments A-19, a-b above).
Regarding the comment from WPTF, ARB staff believes this language is redundant with the language earlier in the sentence where it clearly states that a power contract applies to specified sources, and therefore declines to make the suggested change. The additions to section 95111(a)(4) already include the requirements of the seller warranty. Regarding the comment from Powerex, ARB staff believes that because the definition of specified source includes references to an ACS, the change proposed by Powerex is unnecessary. Also, see response to A-10 [OP 26.02 – PX].

A-20a Specified Source, Section 95102(a)(432)

Comment: TransAlta requests that ARB clarify who is eligible to be the first seller of a specified source in the market path, by altering the specified source definition to include the term Generation Providing Entity as shown below. TransAlta states that the definition change would clarify who has the ability to sell power from a generation source as specified source, and act as the first seller in a specified source transaction chain.

95102(a)(432) "Specified source of electricity" or "specified source" means a facility or unit which is permitted to be claimed as the source of electricity delivered. The reporting entity must be a Generation Providing Entity of the source or have either full or partial ownership in the facility/unit, or have a written power contract to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity procured from an asset-controlling supplier recognized by the ARB. [OP 05.03 – TA]

A-20b Specified Source, Section 95102(a)(432)

Comment: WPTF requests that ARB revise the Specified Source definition in section 95102(a)(432) to include the term "generation providing entity" in order to make the two definitions consistent. WPTF proposes the following language:

(432) "Specified source of electricity" or "specified source" means a facility or unit which is permitted to be claimed as the source of electricity delivered. The reporting entity must be a Generation Providing Entity for ~~have either full or partial ownership in~~ the facility/unit, or have a written power contract to procure electricity generated by that facility,~~/~~unit or system. Specified facilities/units include cogeneration systems. Specified source also means electricity procured from an asset-controlling supplier recognized by the ARB. [OP 02.03 – WPTF]

A-20c Specified Source, Section 95102(a)(432)

Comment: Powerex. To maintain alignment with the dual requirement of a written power contract and direct delivery, and consistency with the proposed new MRR § 95111(a)(5)(E), Powerex respectfully submits that the specified source definition should be clarified to refer to the system of an ACS entity.

> **§95102(432)** "Specified source of electricity" or "specified source" means a facility or unit which is permitted to be claimed as the source of electricity delivered. The reporting entity must have either full or partial ownership in the facility/unit or a written power contract to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity delivered from the system of **~~procured from~~** an asset controlling supplier recognized by the ARB.

[OP 26.05 – PX]

Response: For comments A-20a and A-20b, please see response to comment A-16 [OP 02.02]. For comment A-20c, please see response to comment A-10 [OP 26.02].

A-21. Treaty Power, Section 95102(a)(476)

Comment: BPA does not take issue with the proposed change regarding treaty power in 95111(b)(3), other than to point out that the Canadian Entitlement is not "purchased" from BPA in a market transaction. Rather, BPA provides the power as a return of benefit pursuant to the requirements of the Columbia River Treaty. BPA's primary reason for commenting on this issue is to point out that BPA does not agree with the proposed definition of Treaty power, specifically, the statement that it should be accorded an emission factor of zero. Instead, BPA suggests modifying proposed definition #476 as explained below.

Under the Columbia River Treaty, BPA supplies Canadian Entitlement (CE) energy to Powerex from BPA's entire system of resources, including market purchases. Powerex acknowledges this in its August 15th comment: "The treaty obligation to deliver CE energy is an obligation of the United States to deliver a certain fixed amount of power each year, *not an obligation to provide a certain percentage of power from any specific sources*." The Canadian Entitlement is scheduled to meet Canada's needs and is shaped on a daily and hourly basis to ensure equal average monthly delivery amounts. In order to meet these variable Canadian schedules, BPA relies not only on hydro generation but also on other resources in its entire system. In contrast, if the Canadian Entitlement were truly delivered as zero emission factor hydro generation (as definition #476 is currently written by providing an emission factor of zero to Treaty power), then the power would be delivered to Powerex in the shape of BPA's hydro generation with larger amounts in some months than in others. Thus, a more accurate way to account for the power would be to accord it an emission factor equivalent to BPA's ACS emission factor for the year in question.

Powerex is correct that "the CE reflects Canada's 50% share of the downstream power benefits derived from hydroelectric generation in the United States," but this is simply the basis for the calculation of total *amount* of benefit, not its *source*. The statement does not support Powerex's conclusion that "it is abundantly clear that CE power should be treated as zero EF power." Powerex is merely citing to the basis for how the *amount* of Canadian Entitlement power is determined; this does not reflect the operational reality of how that power is *supplied*. Accordingly, BPA suggests that CARB change the proposed definition #476. The final sentence of the definition should be modified to read "Treaty power shall be accorded an emission factor equal to the ACS or other source from which it was supplied."

Lastly, BPA notes that the responsibility for providing approximately 125 of the 500 aMWs (average annual megawatts) of the monthly Canadian Entitlement amount has been allocated to the owners of the five non-Federal hydroelectric projects along the Columbia River. These owners, who are not affiliated with BPA, are referred to as the "Mid-C" participants. Accordingly, the Canadian Entitlement obligation is met by ~375aMWs from the BPA ACS System and ~125 aMWs from generation from the Mid-C participants. BPA has no involvement with how or where the Mid-C participants procure the MWs to meet their monthly 125 aMW Treaty obligation. [OP 18.03 – BPA]

Response: Although proposed in the 45-day draft, after further consideration and review of stakeholder comments, ARB staff has removed all references to treaty power in the 15-day changes. Under the asset-controlling supplier system emission factor, an asset-controlling supplier must report its actual power deliveries to obtain the ACS factor. While an international treaty, like the Columbia River Treaty, may result in an entity receiving a certain amount of power, ARB understands that the treaty does not specify any type of source for that power. As such, the concept of treaty power does not correspond to the actual power deliveries which are accounted for in an ACS system factor. For this reason, ARB staff will continue to account for power in the ACS system emission factor calculation through the purchased wholesale electricity (PE_{sp}) variable under the existing provisions of 95111(b)(3). Power obtained pursuant to a treaty would be reported as it is actually delivered, which could be specified or unspecified, depending on the actual power. This is consistent with provisions for claiming specified source power, including the requirement to document actual power deliveries via NERC e-tag.

A-22a Definition for Activin

Comment: "Activin" is a brand name and not an accurate description of the material. The most accurate name of this product is "Grape Seed Extract." Please change 95102 b (1) to "Grape Seed Extract." [OP 03.01 – EJG]

A-22b Definition for Activin

Comment: Commenter reiterated comment OP 03.01. [OP 04.01 – EJG]

Response: ARB staff declines to make this edit at this time. ARB staff believes that the descriptor 'grape seed extract' can be applied to the definition of 'activin' without a regulatory change. ARB staff, as needed, will issue guidance on this issue to further explain the reporting requirements and is committed to working with the commenter to ensure its product data is reported and verified correctly.

A-23a. Definition for Crystal Color Concentrate

Comment: Crystal is a brand and not an accurate description of the material. "Dry Color Concentrate" is a more accurate descripting of this product. Please change 95102 b (25) to "Dry Color Concentrate." [OP 03.02 – EJG]

A-23b. Definition for Crystal Color Concentrate

Comment:

Commenter reiterated comment OP 03.02. [OP 04.02 – EJG]

Response: Based on stakeholder input, the definition was modified in the 15-day changes as requested.

A-24. Definitions for Food Processing Categories

Comment: CLFP agrees with the proposed definitions regarding food processing categories under section 95104(b) as specified:

(6) “Aseptic” is the process by which a sterile (aseptic) product (typically food or pharmaceutical) is packaged in a sterile container in a way that maintains sterility.

(7) “Aseptic tomato paste” means tomato paste packaged using aseptic preparation. Aseptic paste is normalized to 31 percent tomato soluble solids (TSS). Aseptic Paste Normalized to 31% TSS =(%TSS - 5.28)/(31 - 5.28)

(8) “Aseptic whole/diced tomato” means the sum of whole and diced tomatoes packaged using aseptic preparation. Sum of Whole and Diced = Whole Tomatoes + (Diced Tomatoes x 1.05))

(12) ""Canned non-tomato additive"" means a canned food product produced at a tomato processing facility that is not aseptic tomato paste, aseptic whole/diced, non-aseptic tomato paste, non-aseptic whole/diced, non-aseptic tomato juice, or canned non-tomato additive.

(15) ""Cheese"" means a food product derived from milk that is produced in a wide range of flavors, textures, and forms by coagulation of the milk protein casein.

(54) “Non-Aseptic tomato juice” means tomato juice packaged using methods other than aseptic preparation.

(55) “Non-Aseptic tomato paste” means tomato paste packaged using methods other than aseptic preparation. Non-Aseptic paste is normalized to 24 percent tomato soluble solids (TSS). Non-Aseptic Paste Normalized to 24% TSS = (%TSS - 5.28)/(24 - 5.28).

(56) “Non-Aseptic whole/diced tomato” means the sum of whole and diced tomatoes packaged using methods other than aseptic preparation. Sum of Non-Aseptic Whole and Diced = Whole Tomatoes + (Diced Tomatoes x 1.05).

(82) “Tomato Juice” is the liquid obtained from mature tomatoes conforming to the characteristics of the fruit Lycopersicum esculentum P. Mill, of red or reddish varieties. Tomato juice may contain salt, lemon juice, sodium bicarbonate, water, spices and/or flavoring.

(83) “Tomato Paste” is the food prepared from mature tomatoes conforming to the characteristics of the fruit Lycopersicum esculentum P. Mill, of red or reddish varieties.

Tomato paste is prepared by concentrating tomato ingredients until the food contains not less than 24.0 percent tomato soluble solids.

(84) “Tomato soluble solids” means the sucrose value as determined by the method prescribed in the “Official Methods of Analysis of the Association of Official Analytical Chemists,” 13th Ed., 1980, sections 32.014 to 32.016 and 52.012. For instances where no salt has been added, the sucrose value obtained from the referenced tables shall be considered the percent of tomato soluble solids. If salt has been added either intentionally or through the application of the acidified break, determine the percent of such added sodium chloride as specified in the definition of salt. Subtract the percentage sodium chloride from the percentage of total soluble solids found (sucrose value from the refractive index tables) and multiply the difference by 1.016. The resultant value is considered the percent of “tomato soluble solids.”

(90) “Whole Peeled Tomatoes” is the food prepared from mature tomatoes conforming to the characteristics of the fruit Lycopersicum esculentum P. Mill, of red or reddish varieties. The tomatoes are peeled but kept whole, and shall have had the stems and calicies removed and shall have been cored, except where the internal core is insignificant to texture and appearance.

CLFP will continue to work with ARB Staff to amend those definitions that do not accurately identify or define the products, materials, produce, or raw product that constitute the basis for the food processing industry." [OP 36.02 – CLFP]

Response: ARB staff appreciates the commenter’s support for the above definitions.

A-25. CWB Definitions

Comment: Proposed Mandatory Report Rule CWB Definitions. Process unit definitions that are too specific risk confusion and problems during verification and may require ongoing changes as new technology is developed. ARB can ease this issue by clearly listing these definitions under CWB and prefacing them as “intended for the purpose of guiding the calculation of CWB.”

While we understand the need for a core description, there are also dangers in specific lists of feeds and products. If a specific definition does not include all possibilities, the verifier may not be able to match a process unit directly to its definition. We recommend that broader language in these areas be included in each of the definitions. For example, “feeds include but are not limited to…” and “products include but are not limited to…”

We suggest that ARB either adopt the process unit definitions provided by WSPA, since these adhere more closely to the definitions provided by Solomon in Appendix D of their May 17, 2013 document or defer all but the largest process unit definitions to guidance. If ARB does not use the Solomon definitions provided by WSPA, the changes outlined in Attachment 2 are necessary.

Attachment 2: Suggested modifications to refinery process unit definitions:
In order to minimize confusion, ARB should use the process unit definitions provided by WSPA, since these adhere more closely to the definitions provided by Solomon in Appendix D of the May 17, 2013 document provided to ARB by WSPA. If ARB does not use the Solomon definitions provided by WSPA, the changes below are necessary.

The definitions should broadly acknowledge that they are intended for the purpose of guiding the calculation of CWB.

In general, broader language should be included in each of the definitions. For example, “feeds to the unit include but are not limited to…” “Products include but are not limited to…”

Add “C5” and “C9” to the definition for ‘Alkylation/poly/dimersol’ to read: “Alkylation/poly/dimersol means a range of processes transforming C3/C4/C5 molecules into C7/C8/C9 molecules…”.

Expand the definition of “Ammonia recovery unit” to read: “Ammonia recovery unit means a refinery unit in which ammonia-rich sour water stripper overhead is treated to separate ammonia suitable for reuse in the refinery, or sales, for fertilizer, for the reduction of NOx emissions, or other commercial activities. This unit is the second stage of a two stage sour water stripping unit. The ammonia recovery unit includes, but is not limited to, the adsorber, stripper and fractionator.”

Delete “and disposed of” in the definition of “Delayed Coker” as follows: “Delayed Coker means a refinery unit which conducts a semi-continuous process, similar in line-up to a visbreaker, where the heat of reaction is supplied by a fired heater. Coke is produced in alternate drums that are swapped at regular intervals. Coke is cut out of full coke drums as a product. For the purposes of analysis, facilities include coke handling and storage.”

In the definition of “Distillate Hydrotreating”, “virgin kerosene” should be changed to “distillate”, because hydrotreaters do not necessarily treat fresh feed—it may come from other refinery units.

Revise the definition of “Flexicoker” to read: “Flexicoker means a refinery unit which conducts a proprietary process incorporating a fluid coker and where the [delete ‘surplus’] coke is gasified to produce a so-called ‘low BTU gas’ which is used to supply the refinery heaters and surplus coke is drawn off as a product.”

In the definition of “Fluid Catalytic Cracking”, we propose more general language such as “Fluid Catalytic Cracking means cracking of feedstocks such as vacuum gasoil and residual feedstocks over a finely divided catalyst.”

Delete “and disposed of” in the definition of “Fluid Coker” to read: “Fluid Coker means a proprietary continuous process where the fluidized powder-like coke is transferred between the cracking reactor and the coke burning vessel and burned for process heat production. Surplus coke is drawn off as a product.”

Add “or coker” the definition of “Propane/Propylene splitter” to read: “Propane/Propylene splitter (propylene production) means a refinery unit that conducts separation of propylene from other mostly olefinic C3/C4 molecules generally produced in an FCC or coker. Its products include propylene and must be chemical or polymer grade. "Chemical" and "polymer" are two grades with different purities.”

In the definition of “Selective Hydrotreating of distillates”, 1) We propose that “of distillates” be replaced with “C3-C5 streams for alkylation.” Feeds to these units can include feeds that are lighter than distillates.

Revise the definition of “Vacuum Distillation” to read: “Vacuum Distillation means distillation of atmospheric residues under vacuum.” Delete “The process line up must include a heater” because some units may have more than one main distillation column.

Delete “vacuum gasoils usually destined to be used as FCC feed” from the definition of “VGO Hydrotreater” to read: “VGO Hydrotreater means a refinery unit which conducts desulfurization of a hydrocarbon stream typically made up of vacuum gasoils and cracked gasoils, principally destined to be used as FCC feed, over a fixed catalyst bed at medium or high pressure and in the presence of hydrogen.” [OP 10.04 – CC]

Response: ARB staff met with the stakeholder to discuss each of the definitions listed above. The definitions related to the complexity weighted barrel in section 95102(c) were modified to address the concerns of the above comment and included in the proposed 15-day modifications. In general, the term “but not limited to” was not included by ARB staff. Instead, the word “may” was used.

ARB staff added the values “C5 and C9” to the definition of “Alkylation/poly/dimersol”

ARB staff accepted the proposed changes for “ammonia recovery unit.”

ARB staff accepted the proposed changes for “delayed coker.”

ARB staff accepted the proposed changes for “distillate hydrotreating” by deleting “virgin kerosene” and replacing it with the word “distillate.”

ARB staff deleted the term “surplus” from the definition of “Flexicoker.”

ARB staff modified the term “fluid catalytic cracking” based upon the suggestion of the commenter. However, the exact language was not used to maintain some specificity. The word ‘may’ was added for flexibility.

ARB staff accepted the proposed changes for “fluid coker.”

ARB staff accepted the proposed change for “propane/propylene splitter”

ARB staff accepted the proposed change to “selective hydrotreating of C3-C5 streams for alkylation.”

ARB staff accepted the proposed changes to “vacuum distillation.”

ARB staff accepted the proposed changes to “VGO hydrotreater.”

§95103 – Greenhouse Gas Reporting Requirements

A-26. Maintain Confidentiality of Customer Data

Comment:

Protection of Privacy

Section 95103(a)(1) states the following:

Facility name, assigned ARB identification number, physical street address including the city, state and zip code, air basin, air district, county geographic location, natural gas supplier name, natural gas supplier customer identification number, natural gas supplier service account identification number or other primary account identifier, and annual billed MMBtu (10 therms = 1 MMBtu).

Please note, however, individual customer information including customer name and account number is considered private and must be handled as confidential information pursuant to Public Utilities Code Sections 581 and 583, General Order 66-c and Public Utilities Code section 8380. Any public disclosure by ARB of individual customer information would, therefore, be prohibited. SoCalGas and SDG&E recommend removing the requirement to provide service account identification number.

SoCalGas and SDG&E recommend removing the requirement to provide the ARB ID for end user facilities. SoCalGas and SDG&E have the ARB ID # for the facilities with ≥ 25,000 CO_2e emissions, but do not have the ARB ID Nos. for the facilities with <25,000 CO_2e. The only way to collect this data would be to call the end-user directly and ask them for that number, which is a time-consuming and duplicative task considering ARB already has the ARB ID #s for all reporting facilities. [B 02.08 – SU]

Response: ARB agrees that this data would be confidential, and intends to maintain the data as confidential consistent with California law. As specified in section 95106 of the MRR, reporters have the opportunity to clearly identify data as confidential during the report certification and submission process. Because the data discussed by the commenter are not emissions data, if ARB were to receive an outside request for the data, ARB would follow the requirements of the California Public Records Act (Government Code section 6250 et seq.) and the procedures set forth in title 17, California Code of Regulations, section 91000 to 91022 which specify how such requests are handled. This provides a mechanism for reporters to prevent the release of data that is confidential or industry-sensitive.

Regarding the requirement to provide the ARB ID for end user facilities, this data, including facilities with <25,000 mt of CO_2e, allows ARB staff to accurately calculate a covered emissions value for each natural gas supplier. ARB staff declines to make the suggested change. Also, see the response to comment A-1.

A-27. Retain Current Reporting and Verification Deadlines.

Comment: The proposed changes to the Regulation do not include changes to the emissions report deadline in section 95103(e) or the verification deadline in section 95103(f), despite earlier proposals to move the verification deadline (and possibly also the reporting deadline) two weeks earlier. SCPPA commends the ARB on retaining the existing deadlines. Moving these deadlines earlier would have imposed difficulties on all covered entities. Verification is a detailed and time-consuming process that would be difficult to compress into a shorter timeframe. In addition to completing initial investigations, document review and site visits, there needs to be a period of dialog between the verifier and the covered entity to address any questions the verifier may have. An entity may have reports for several facilities, each of which must be verified. Also, a verifier may have several clients, all requiring verification during the same period. Shortening the time for verification would have made it more difficult for the verifier to complete a thorough verification and for the covered entity to respond to any questions. Moving the reporting deadlines two weeks earlier (so as to allow the same length of time for verification) would have imposed a host of additional difficulties. Facilities and entities have to submit reports to multiple agencies. An earlier reporting deadline under the Regulation would overlap with reports due to local air quality management districts and the US Environmental Protection Agency, making it very difficult for reporting staff to spend the necessary time to ensure each report is accurate and complete. [OP 12.03 – SCPPA]

Response: No change required. Staff retained the current reporting and verification deadlines as suggested.

A-28. Reporting in 2014 for 2013

Comment: WSPA appreciates and supports the inclusion of Section 95103(h)(1) which will allow reporters the ability to utilize Best Available Methods (BAM) for quantifying and reporting 2013 GHG emissions as listed within each of the referenced regulatory sections. As stated earlier, WSPA supports ARB's proposal to use CWB instead of CWT and recommends ARB make all necessary revisions and corrections to the MRR and all applicable document in support of CWB only.

Recommendation: WSPA supports ARB's recommendation to use CWB instead of CWT, and if it proceeds with CWB only the BAM provisions as proposed would apply to reporting of CWB throughput data in addition to all the other referenced sections listed in Section 95103(h)(1-11). [OP 08.07 – WSPA]

Response: ARB staff thanks WSPA for its support. This comment does not suggest a regulatory change.

A-29a. Effective Dates for Proposed Electric Power Entity Provisions, Section 95103(h)(8).

Comment: WPTF contends that the owner of electricity generated by a particular source should control whether that electricity sold from that source is specified. However, ARB's proposed language does more than interpret and implement existing requirements. The change to 95111(a)(4) is a wholly new requirement and should not be applied to transactions that are executed any time before when these revised regulations are approved by the Office of Administrative Law. Similarly, if CARB adopts WPTF's proposed revisions to the definitions of power contract and GPE, these changes should apply prospectively. Otherwise, CARB would be retroactively applying new legal requirements. In short, because the requirements for claiming of specified power have evolved over the past year, it would be unfair to apply a new requirement that sellers warrant the sale of specified source electricity to contracts that were executed prior to the date of the regulatory change.

WPTF appreciates that staff have attempted to address this concern in section 95103(h)(8) as proposed, but this is not adequate. The language reads:

"Electric power entities must report 2013 electricity transactions (MWh) and emissions under the specifications of this article, including the requirements listed in sections 95111(a)(4)(A)(3), 95111(a)(5), 95111(b)(3), 95111(f)(5)(F) and 95111(g)(1)(N)"

The proposed language is insufficient for several reasons. First, 95103(h)(8) refers to entire paragraphs of the regulation, but does not distinguish between individual provisions that have been amended within those paragraphs. Thus, for example, it appears to exclude the entirety of paragraph 95111(a)(4) from application for 2014 reporting, as opposed to the new seller warranty requirement only. Second, use of the word 'including' suggests that other sections, in addition to those delineated 95103(h)(8), apply for 2014. Third, the language only differentiates between the dates of electricity transactions; it does not differentiate between the execution dates of the underlying contracts.

Given the ambiguity in the language of 95103(h)(8), WPTF recommends that the most thorough and efficient way to bring certainty to the applicability of new requirements for specified contracts is for them to be clearly set out in the relevant definitions and operational sections of the text. We provide an example for section 95111(a)(4) as follows:

For power contracts executed after December 31, 2013 the sale or resale of specified source electricity is permitted among entities on the e-tag market path insofar as each sale or resale is for specified source electricity in which sellers have purchased and sold specified source electricity, such that each seller warrants the sale of specified source electricity from the source through the market path.

If is not possible to address the applicability of new requirements throughout the MRR text, then WPTF requests that CARB issue implementation guidance on the applicability of the changes for electricity importers. This guidance should be issued before the end of the calendar year, should address all substantive changes to the regulation, and should clearly indicate what changes apply for different reporting years, and what changes apply for new contracts.
[OP 02.09 — WPTF]

A-29b. Effective Dates for Proposed Electric Power Entity Provisions, Section 95103(h)(8).

Comment: WPTF submitted comments restating its concern regarding the effective dates for the proposed provisions and section 95103(h)(8) from Comment Letter OP 02. [B 03.03 – WPTF]

A-29c. Effective Dates for Proposed Electric Power Entity Provisions, Section 95103(h)(8).

Comment: The above comments were reiterated during public testimony at the board hearing as well. [T 12.03 — WPTF]

A-29d. Effective Dates for Proposed Electric Power Entity Provisions, Section 95103(h)(8).

Comment: SCPPA states that proposed new section 95103(h)(8) provides that electric power entities must report 2013 electricity transactions and emissions in accordance with the requirements of sections 95111(a)(4)(A)(3), (a)(5), (b)(3), (f)(5)(F) and (g)(1)(N). Effectively, therefore, the proposed changes to these parts of section 95111 will be retroactive to the start of 2013, although the changes will not be finalized and approved until towards the end of 2013. As a general rule, SCPPA does not support the retroactive application of changes to regulations – particularly changes that will be made retroactive back nearly a full year before they are finalized.

However, the retroactivity of the proposed change to section 95111(a)(5)(B) is a particular concern. Section 95111(a)(5)(B) currently provides that electricity delivered from asset-controlling suppliers must be reported as specified and not as unspecified. The proposed change deletes this sentence altogether and substitutes it with a requirement to report as unspecified power, asset- controlling supplier (“ACS”) power that was not properly acquired as specified power. This change virtually reverses the meaning of this section. Rather than being required to report all electricity delivered from ACSs as specified, the section would allow only certain purchases of ACS electricity to be claimed as specified. The requirements for claiming specified source power include having a written power contract that is contingent upon delivery of power from a particular facility or ACS system that is designated at the time the transaction is executed, according to the definition of “power contract” in section 95102(a)(356). Some SCPPA members have long-term power contracts with ACSs that do not specifically designate the source of the power as the ACS’s system. However, the power delivered by the ACS does come from its system, as shown by the e-tags. These contracts have been in place for some years. In the 2012 emissions report, this power could be (and was) claimed as ACS power with the relevant ACS emissions factor, due in part to the requirement in current section 95111(a)(5)(B) to report electricity delivered from asset-controlling suppliers as specified and not as unspecified. If the proposed change to section 95111(a)(5)(B) is made retroactive to the start of 2013, the power from these contracts could not be claimed as ACS power and must be reported as unspecified (using the default emissions factor) in the 2013 data year report and future reports. Given the difference between ACS emission factors and the default emissions factor, an electricity importer’s reported emissions, and its emissions liability, would increase (as between 2012 and 2013) without any change in the source of its power or its actual emissions. This is not appropriate.

Furthermore, this impact could not be avoided by simply amending the power contract with the ACS to specify the source of the power, because the source must be specified at the time the transaction is executed. A whole new contract would need to be entered into, raising a host of potential commercial issues. For these reasons, the change to section 95111(a)(5)(B) should apply only to transactions entered into after these proposed changes to the regulation become effective, which SCPPA understands will be on January 1, 2014. Going forward, electricity importers would be aware that any new contracts with ACSs must specify the source of the power and could take steps to include this provision when negotiating new contracts. This approach would avoid unfairly penalizing those importers with existing ACS contracts that do not happen to specify the source and that were entered into when there was no requirement to specify the source. [OP 12.04 — SCPPA].

A-29e. Effective Dates for Proposed Electric Power Entity Provisions, Section 95103(h)(8).

Comment: During oral comments before the Board, SCPPA reiterated its concern regarding the effective dates for the proposed provisions. [T 01.02 — SCPPA]

A-29f. Effective Dates for Proposed Electric Power Entity Provisions, Section 95103(h)(8).

Comment: LADWP**.** §95103(h) Reporting in 2014: amendments pertaining to contracts for electricity purchases should not be applied retroactively to the 2013 data report.

Section §95103(h) contains a list of the 2013 amendments that will apply to 2013 data reported in 2014. Any 2013 amendments not listed in 95103(h) will apply to 2014 data reported in 2015. Section 95103(h)(8) states that electric power entities must report 2013 electricity transactions (MWh) and emissions (metric tons of CO2e) under requirements listed in the following sections:

- 95111(a)(4)(A)(3) – Imported Electricity from Specified Facilities or Units
- 95111(a)(5) – Imported Electricity Supplied by Asset-Controlling Suppliers
- 95111(b)(3) – Calculating GHG Emissions of Imported Electricity Supplied by Asset-Controlling Suppliers
- 95111(f)(5)(F) – Requirements for Asset-Controlling Suppliers
- 95111(g)(1)(N) – Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment

Thus, the proposed amendments in each of the above listed sections would be retroactive to the start of the 2013 calendar year. LADWP is very concerned that 95111(a)(5)(B) includes a new requirement to have a specific type of contract in order to report Asset Controlling Supplier power as a specified import. It is not appropriate to apply new requirements pertaining to contracts for electricity purchases retroactively to transactions that have already been completed. The 2013 emission data reports should be governed by the rule language that was in effect during the 2013 period. The new requirement in 95111(a)(5)(B) should apply to new transactions executed after January 1, 2014 after the 2013 rule amendments go into effect. Therefore, 95111(a)(5) should be removed from section 95103(h) or at least limited to amendments within 95111(a)(5) that are not new requirements.

> 95103(h)(8) <u>Electric power entities must report 2013 electricity transactions (MWh) and emissions (metric tons of CO2e) under the specifications of this article, including the requirements listed in sections 95111(a)(4)(A)(3), ~~95111(a)(5)~~, 95111(b)(3), 95111(f)(5)(F) and 95111(g)(1)(N).</u>

[B 01.03 – LADWP]

<u>Response:</u> (this response effective for comments A-29, a-f above)
This response addresses the issue of the effective date for proposed electric power entity provisions itemized in Section 95103(h)(8). In order to clarify which requirements are applicable to reporting of 2013 data in 2014, and to avoid any retroactive application, ARB has removed the following subsection references: sections 95111(a)(4)(A)(3), 95111(b)(3), 95111(f)(5)(F) and 95111(g)(1)(N). In addition, for clarity, ARB has added the following language: "*The requirement that a seller warrant the sale or resale of specified source power in section 95111(a)(4) and the requirement for reporting of asset controlling supplier power in section 95111(a)(5)(B) are effective starting with the reporting of 2014 data in 2015 and later years*." This addresses the concerns in comments A-29a-f above regarding the effective date of these proposed amendments.

A-30. <u>Forward Contracting Under One Version of the Regulation, Section 95103(h)(8).</u>

<u>Comment</u>: TransAlta recommends that ARB make clarifications which acknowledge that a power trade which occurs when one version of the MRR is in place should be verified under those regulatory requirements, and not the regulations in effect at the

time of the first power delivery under that contract. Without this clarification, forward contracting of power is extremely difficult. ARB has commented publically several times that the regulation is not intended to disrupt commercial transactions, and will not be applied retroactively. A modification to this effect would dramatically reduce the risk of forward contracting and allow companies to develop confident long term strategies knowing that contract terms will not be disrupted due to future regulatory amendments and verification requirements. [OP 05.02 – TA]

Response: While ARB staff understands the desire of the commenter for contract certainty going forward, the contract terms discussed by the commenter are negotiated between private parties, not with ARB. The purpose of these regulatory amendments is to ensure that reporting is conducted in as accurate a manner as possible given the state of technology in effect at the time the electricity transactions occur to ensure that all imported power is reported accurately. This reporting must be conducted in a manner to support the current needs of the Cap-and-Trade program as well. As part of these amendments, ARB staff has included the provisions in section 95103(h)(8) to specify which amendments apply to reporting of 2013 data in 2014, and which apply to future data years, in order to provide clarity as to when the amendments take effect. ARB staff believes these provisions ensure that no retroactive application of the regulatory amendments occurs. ARB staff will of course continue to work with stakeholders to evaluate whether future amendments are needed to provide additional clarity.

A-31. 95103(j). Biomethane Reporting Requirements Need Clarification

Comment:

§95103(j)(3) Biomethane Reporting Requirements: additional clarification is needed.

The new requirements added to §95103(j)(3) to report detailed information about biomethane purchases, the biomethane supplier, and the facility that produced the biomethane should be refined and clarified as described below.

- It is not clear what "for each contracted delivery" means. This term should either be deleted or defined for clarification. Biomethane may be purchased under multiple contracts with the same vendor. Does "for each contracted delivery" mean that the quantity of biomethane purchased from that vendor under each individual contract should be reported separately, or should biomethane purchased from the same vendor under multiple contracts be aggregated into an annual total?
- With regards to reporting the "annual MMBtu delivered by each biomethane vendor," if the purchased biomethane is allocated to only one facility, the total annual MMBtu purchased from the vendor and the quantity allocated to the facility would be the same. However, larger entities that operate multiple facilities may subdivide and allocate the purchased biomethane to more than one facility. Since the biomethane purchase information will be reported in a facility level emissions data report, it is reasonable to report the annual MMBtu of biomethane that was purchased and allocated to that particular facility, which may be a subset of the total annual MMBtu of biomethane that the entity purchased from the vendor. Therefore, the "annual MMBtu delivered by each biomethane vendor" should be clarified by adding "that was allocated to the facility".
- The term "delivered" should be changed to "supplied," since biomethane is usually injected into the natural gas pipelines rather than delivered directly to a facility through a separate pipeline.
- If the biomethane is purchased from a marketer that aggregates biomethane from multiple facilities, the purchaser may not have detailed information about the specific facility(ies) that produced the biomethane. Therefore, reporting the name, address and facility type should be "if available."

LADWP recommends clarifying the new biomethane reporting requirements in §95103(j)(3) as follows:

(3) When reporting biomethane, the operator or supplier who is reporting biomass emissions from biomethane fuel must also report the following information ~~for each contracted delivery~~:

(A) Name and address of the ~~biomethane~~ vendor from which biomethane is purchased;

(B) Annual MMBtu ~~delivered~~ supplied by each biomethane vendor that was allocated to the facility.

The operator must also report the name, address, and facility type of the facility from which the biomethane is produced, if available. In addition, relevant documentation including invoices, shipping report, allocation and balancing reports, storage reports, in-kind nomination reports, and contracts must be made available for verifier or ARB review to demonstrate the receipt of eligible biomethane.

[B 01.04 – LADWP]

Response: The specified section requires the reporting of information regarding the sources and delivery of biomethane. Given the potential differences in how biomethane is purchased and delivered to each facility, ARB staff believes that the new reporting requirements are sufficiently clear and broad to capture the necessary biomethane origination data that will be used by verifiers to confirm that reported biomethane meets the requirements listed in section 95852.1.1 of the Cap-and-Trade regulation. Therefore, ARB staff declines to make the suggested changes. Should the reporter have specific questions regarding biomethane reporting in relation to a facility-specific scenario, ARB staff will provide guidance to ensure the necessary data is reported correctly.

A-32. Allow Use of Best Available Methods for Emulsion Reporting

Comment: Upstream facilities impacted by the proposed definition of emulsion (from an offshore platform) will have to begin complying with the additional measurement and reporting requirements associated with this volume starting in 2014, through the use of flash testing. A rule finalized by the end of 2013 does not allow impacted facilities sufficient time to evaluate and make, if needed, infrastructure changes necessary to comply with the newly-applicable flash test requirements. In such situation, engineering calculations and other approved methods would be an appropriate substitute for flash testing in the interim.

Recommendation:
Allow facilities which are newly subject to the emulsion testing and reporting requirements as a result of the proposed regulation changes to use Best Available Methods for 2014 and for such time as reasonably necessary to complete infrastructure changes. [OP 08.16 – WSPA]

Response: Section 95103(h)(4) allows use of best available methods (BAMM) for reporting 2013 data for emulsion reporting. ARB staff contacted the affected reporting entity and ARB staff does not believe that it is necessary to allow an additional year to fully comply with the requirements of the regulation. ARB staff declines to modify this section for 2014 data reported in 2015.

A-33. Reporting De Minimis Biomass-Derived Fuels

Comment: Clarify that section 95103(j)(3) is not applicable for de minimis data. [OP 09.12 – PG&E]

Response: The specified section requires the reporting of information regarding the sources and types of biomass-derived fuels. Staff believes that existing provisions of section 95103(i)(Calculation and Reporting of De Minimis Emissions), which allow the use of best available data for emissions designated as de minimis, are clear that this data is not required to be reported for any emissions identified as de minimis. As such, ARB staff declines to make the requested change to section 95103(j)(3).

A-34. Revise Biomethane Reporting Requirements

Comment: In the proposed revisions to section 95103(j)(3) of the Regulation, the operator of a generating facility that is reporting emissions from biomethane fuel must report, for each contracted delivery, details on each biomethane vendor from which biomethane is purchased and the annual MMBtus delivered by each biomethane vendor.

This provision requires minor changes. First, references to “delivery” of biomethane should be avoided, given that, absent a dedicated pipeline, biomethane itself is not physically delivered to the generator. References to “supply” would be more appropriate.

Second, although reporting is done on a facility basis, an entity may operate several generating facilities and may contract with a biomethane vendor for a volume of biomethane that the entity then allocates among its facilities. Thus, when reporting the annual volume of biomethane supplied by each biomethane vendor under section 95103(j)(3)(B), in each facility report, it would be logical for the entity to report the volume supplied by that vendor that was allocated to that facility rather than reporting the total volume supplied by that vendor. Section 95103(j)(3)(B) should be clarified to reflect this. SCPPA’s proposed changes to section 95103(j)(3) to address the issues outlined above and to reduce redundancy in the drafting are set out below:

> ~~When reporting biomethane, t~~The operator or supplier who is reporting biomass-derived fuel emissions from biomethane fuel must also report, for each contracted supply~~delivery~~:
>
> (A) Name and address of the ~~biomethane~~ vendor from which biomethane is purchased;
>
> (B) Annual MMBtu ~~delivered~~supplied by each biomethane vendor for the facility.
> [OP 12.05 – SCPPA]

Response: Please see response to comment A-31.

A-35. Metering Requirements for CWB Throughput Data

Comment: Chevron testified at the Board hearing that it believes staff should continue working with stakeholders on the meter requirements for the complexity weighted barrel approach through sections 95103 and 95113 to help provide operational flexibility, while still obtaining accurate data. [T 13.02 – CC]

Response: ARB staff appreciates the comments from Chevron and is committed to working with their staff to ensure the measurement accuracy requirements are met regarding the complexity weighted barrel. Additionally, please see response to comment A-40.

A-36. 95103(k). Photographing Orifice Plates

Comment: Section 95103. ARB Should Modify its Measurement Accuracy Requirements. Section 95103(k)(6)(A)(1)(b) requires that the primary element (e.g. orifice plate) "be photographed on both sides prior to any treatment or cleanup of the element to clearly show the condition of the element as it existed in the pipe." This requirement is not part of PG&E's meter maintenance standard S4300, whose inspection frequency requirements are comparable to and whose accuracy requirements are more stringent than the ±5% specified in the MRR (95103 (k)). Requiring a photograph of the orifice plate, given the robustness of PG&E's standard S4300, is superfluous.

Pipeline quality natural gas, which is subject to strict standards for entrained liquids and other materials, is unlikely to foul an orifice plate to the extent it would push meter accuracy outside the ±5% window. Routine meter inspection, maintenance, and calibration as specified in PG&E's standard S4300 will ensure timely corrective action for any rare instance of fouling that may occur. Therefore, PG&E strongly recommends that flow meters measuring natural gas be exempt from the requirement to photograph their orifice plates. [OP 09.05 – PG&E]

Response: The comment refers to a provision of the existing regulation which has not been modified as part of this rulemaking and is therefore outside the scope of this rulemaking. Notwithstanding this, ARB staff responds as follows: ARB staff has already proposed in amended section 95103(k)(7)(C) to allow Public Utility Gas Corporations to allow Public Utility Gas Corporations to use internal metering standards that meet CPUC General Order 58A accuracy requirements for meters that do not qualify as "transaction meters." Meters maintained according to such internal standards are exempt from the ARB specified calibration requirements. Therefore, ARB staff believes no further changes are needed to address the commenter's concern.

A-37. 95103(k) Metering Requirements

Comment: We have a specific request in two areas of the proposal. We ask the Board to not act on the strike out on page B15 Section K11 and also not act on Section E on page B22. We ask the Board not act on these changes because this is, to us, relatively new change and proposals may have serious ramifications on facilities operations up to and including the unit shut down for metered calibration. If after consultation with stakeholders ARB remains convinced that these changes need to be made, they could be done -- achieved at that time.. [T 10.04 – WSPA]

Response: Please see response to comment A-40

A-38. Excessive Accuracy Requirements for Natural Gas Utilities

Comment:

Measurement Accuracy Requirement - §95103(k)

SDG&E and SoCalGas find some of the field accuracy assessment requirements in §95103(k)(6) excessive when applied to natural gas utilities. As regulated California utilities, SoCalGas and SDG&E have adhered for decades to strict CPUC measurement standards with more stringent accuracy intervals than those in the MRR. Based on our gas standards covering field meter accuracy tests to assure compliance with CPUC orders, and an audit services department that evaluates internal controls including review of system-wide gas measurement records, we believe additional exemptions should be afforded to California's regulated utilities. Specifically, the requirement [95103(k)(6)(A)(1)(b)] to photograph both sides of the primary element (such as an orifice plate) of pressure differential devices is unnecessary. We request this requirement be eliminated for measurement flow devices operated and maintained by natural gas utilities.

[B 02.04 - SU]

Response: The comment refers to a provision of the existing regulation which has not been modified as part of this rulemaking and is therefore outside the scope of this rulemaking. Notwithstanding this, ARB staff responds as follows: ARB staff has already proposed in amended section 95103(k)(7)(C) to allow Public Utility Gas Corporations to use internal metering standards that meet CPUC General Order 58A accuracy requirements for meters that do not qualify as "transaction meters." Meters maintained according to such internal standards are exempt from the ARB specified calibration requirements. Therefore, ARB staff believes no further changes are needed to address the commenter's concern.

A-39. Provide Time to Incorporate Changes to Regulation

Comment: Allow time to update monitoring and calculation methods after a change to the regulation. Proposed new section 95103(m)(5) provides that:

When regulatory changes impose new or revised reporting requirements or calculation methods on an operator or supplier, the monitoring and calculation method must be in place on January 1 of the year in which data is first required to be collected pursuant to the reporting requirements.

It may take a period of time for a reporting entity to adopt new or revised monitoring and calculation methods following a change to the Regulation. If the changes to the Regulation occur towards the end of a year, it may not be possible to adopt the new methods by January 1 of the following year. To allow a reasonable period of time for an entity to adopt new methods, section 95103(m)(5) should be revised as follows:

> When regulatory changes impose new or revised reporting requirements or calculation methods on an operator or supplier, the monitoring and calculation method must be in place by the later of 60 days after the regulatory changes take effect, or~~on~~ January 1 of the year in which data is first required to be collected pursuant to the reporting requirements.

[OP 12.06 – SCPPA]

Response: ARB staff declines to make this edit. In order to ensure accuracy of the reported data on an annual basis, reporting entities need to ensure all procedures are in place by January 1.

A-40. Data Collection Methodology

Comment: 2014 Data Collection and Reporting Requirements. WSPA appreciates ARB staff's efforts in working closely with WSPA and WSPA members on the myriad of MRR reporting complexities involving data, monitoring, documentation and analysis including the verification process. As ARB and stakeholders have worked through the AB32 MRR program, it has become clear that reporting requirements are extraordinarily complicated. With each subsequent regulatory revision additional requirements have in many instances only increased the complexity resulting in significant challenges for reporters to ensure all new revisions and reporting requirements are met both within very stringent accuracy standards and timeframe schedules.

In that regard, while WSPA supports staff incorporating BAM provisions for the 2013 data collection year WSPA members are very concerned whether there is sufficient clarity and understanding on all aspects of the MRR reporting regulations going forward into 2014. For example, in December 2012 ARB issued a document entitled: "*Guidance on Reporting requirements for the Carbon Dioxide Weighted Tonne (CWT)*" ("Guidance") to provide guidance on reporting requirements for CWT product meters. The guidance allowed reporters the ability to demonstrate CWT meter accuracy through 95103(k)(11) in lieu of having to follow 95103(k)(1-10) requirements. Further, in its 45 day draft ARB proposed revisions to Section 95103(k)(11) which incorporated "*process throughputs in sections 95113(l)(3)-(4)*". As ARB is aware, WSPA supports these changes.

However, at ARB’s October 7, 2013 C&T workshop ARB released a document entitled: “Language to Support Complexity Weighted Barrel (CWB)” in support of the proposed revisions. Item (E) on page 2 of the document, states that all throughputs must follow the accuracy requirements outlined in section 95103(k). WSPA is concerned that this new language is confusing and could be interpreted to mean that operators who plan on utilizing the ARB Guidance document to demonstrate CWB meter accuracy are now required to follow 95103(k)(1-10) requirements regardless of what the methodology may be as opposed to 95103(k)(11).

While we understand ARB’s intent in the above referenced sections, it is unreasonable, if not impossible, to expect reporters to have a clear understanding of the final regulatory requirements they are subject to, especially because the proposed revisions will become final on or about the same time the regulation becomes effective (i.e., January 1, 2014). As in any regulation where revisions are proposed, facilities that are subject to these new requirements must be able to have sufficient time to comply with them once they become final.

To avoid any potential situations where a requirement was either not clear, a result of different interpretation, a new change, or simply unforeseen, WSPA recommends ARB incorporate the following recommendations that will help reporters better understand in advance and have options to comply with any new methodologies in data collection and calculation changes prior to the January 1 deadline date. This is especially important given the fact ARB is in the processes of finalizing their proposal to use CWB instead of CWT and the need exists for clear guidance going forward in 2014. The ability to identify options to reporting is particularly important in the event new requirements arise that were unforeseen or due to interpretation issues resulting in having to meet stringent deadline requirements (i.e., January 1 of each year).

Recommendation #1:
WSPA recommends ARB develop a list or table that describes the specific proposed changes so that it is clear to reporters which of the new changes would require data collection/reporting as a result of changes in methodology by January 1, 2014.

Recommendation #2:
WSPA recommends ARB extend the use of Best Available Methods (BAM) through 2014 for refinery product data reporting. This will allow reporters sufficient time to transition to the CWB methodology, including calculations and reporting requirements, as well as time to implement the alternative CWB product meter demonstration of accuracy requirements that are specified in ARB’s Guidance document (which will need to be updated to reflect CWB requirements).

Recommendation #3:
WSPA recommends ARB clarify in the Guidance document that reporters who voluntarily elect to pull and inspect product CWB meters (on a scheduled turnaround basis); may list the meters and planned time schedule in their Monitoring Plan in lieu of having to submit a postponement request pursuant to Section 95103(k)(9).

Recommendation #4:
WSPA recommends ARB revise Section 95103(m)(5) to clarify that operators have the ability to request an alternative monitoring methodology approval from the Executive Officer during the data collection year[WSPA's recommended language shown in red].

"Section 95103

(m) *Changes in Methodology*. Except as specified below, where this article permits choices between different methods for the monitoring and calculation of GHGs **and product data**, the operator or supplier must make this choice by January 1, 2013, unless new or revised regulatory changes were made to reporting requirements or calculations, that requires the reporter to install new equipment or revise calculations; in which case the method must be in place on January 1 of the following year. ~~unless the use of an alternative calculation method is approved in advance by the Executive Officer~~ An operator or supplier can utilize an alternative calculation method pursuant to Section 95109(A) & (B), and ARB Guidance; within the data collection year, subject to approval ~~in~~ by the Executive Officer.

~~(5) When regulatory changes impose new or revised reporting requirements or calculation methods on an operator or supplier, the monitoring and calculation method must be in place on January 1 of the year in which data is first required to be collected pursuant to the reporting requirements.~~

Recommendation #5**:**
Consistent with our earlier comments, WSPA recommends ARB revise the December, 2012 "*Guidance on Reporting requirements for the Carbon Dioxide Weighted Tonne (CWT)*" ("Guidance") to CWB metric units. [OP 08.08 – WSPA]

Response: One of the main goals of the measurement accuracy requirements is to ensure data reported under the reporting regulation is sufficiently accurate to support a market-based Cap-and-Trade program. To this end, ARB staff has worked closely with WSPA members to ensure the requirements are applied fairly and consistently to refinery and other sectors subject to these requirements.

In the 15-day proposed amendments, ARB staff deleted the language in 95103(k)(11) allowing the use of this section for the carbon dioxide weighted tonne and complexity weighted barrel. This section was added in the 45-day rulemaking package for consistency with the guidance released earlier in the year on carbon dioxide weighted tonne. By moving to complexity weighted barrel, ARB staff wanted to ensure accuracy of reported product data that is used to support the allocation of allowances in the Cap-and-Trade program.

Further, ARB staff clarified the requirements in section 95113(l)(3)(E) to indicate which paragraphs in the metering section apply to the complexity weighted barrel. Language was also added in the 15-day changes to add flexibility to the postponement request process. With these modifications, ARB staff believes the accuracy requirements for complexity weighted barrel can be met, while addressing the commenter's concerns on timing and clarity. As such, ARB staff declines to make the specific changes requested by the commenter. ARB staff is of course committed to continuing to work with WSPA to resolve any further questions regarding implementation of the measurement accuracy requirements with updated guidance, as needed.

ARB staff's specific responses to the commenter's recommendations follow:

Recommendation 1: Section 95103(h) includes a listing of the regulatory proposed amendments that are in effect for 2013 data reported in 2014. Regulatory amendments that were not included in the section 95103(h) list take effect for 2014 data reported in 2015. ARB staff, to assist stakeholders with the interpretation of these requirements, may release guidance on this topic, as needed.

Recommendation 2: The throughput reporting requirements for the complexity weighted barrel are not new. In previous amendments to the MRR which took effect on January 1, 2012, section 95113(l)(3)(C) indicated that both barrels and mass units should be reported for the carbon dioxide weighted tonne. Because the majority of the units are in barrels for the complexity weighted barrel, refineries should have been aware of the measurement requirements. For this reason, best available methods will not be allowed for 2014 data reported in 2015.

Recommendation 3: The language in section 95113(l)(3)(E) adds flexibility to the postponement requests. ARB staff also notes that multiple throughputs can be listed in a single postponement request. Staff believes this should reduce the administrative burden for completing these requests.

Recommendation 4: ARB staff does not plan to make the suggested regulatory text edits to section 95103(m). For clarification, this section is designed for two purposes: to ensure a consistent method is used to report emissions or product data, and to ensure there is a means to improve a method, if needed. If a reporting entity wishes to change a method they must petition the Executive Officer to ensure the method change is fully evaluated.

Recommendation 5: ARB staff is committed to ensuring each sector understands the measurement accuracy requirements. To the extent guidance is needed on the complexity weighted barrel requirements, ARB staff is committed to working with WSPA to ensure reporting is done correctly.

§95104 – Emissions Data Report Contents and Mechanism

A-41. Include Requirement to Report Electric Service Account Number

Comment: We appreciate staff's decision to require entities to report their "natural gas supplier service account identification number or primary account identifier." This additional requirement will further ensure PG&E's ability to accurately distribute revenues and costs associated with its Cap-and-Trade compliance obligation as a supplier of natural gas.

For the electric revenue return immediately at hand however, PG&E encourages ARB to require entities to identify an active electric service agreement as well. During the June 26 workshop, staff proposed an amendment that would require reporting entities eligible for Cap-and-Trade auction revenue from the CPUC to report a primary electricity service agreement into which revenue should be deposited. PG&E recommends staff include an amendment consistent with this discussion.

The California Public Utility Commission's (CPUC) Energy Division is developing an interim solution until the MRR amendments become effective, but the Energy Division Final Staff Proposal1 on revenue allocation methodologies for Emissions Intensive Trade Exposed (EITE) customers mentions the following: "In addition to data that ARB already collects or has in its possession, Energy Division will need covered entities to report which primary utility account they wish to have credited with allowance revenue. This information is not currently collected via MRR, but we feel that MRR is the most efficient means of collecting this information on an ongoing basis. We recommend that ARB consider adding to its MRR requirements a new data field that represents the reporting facility's primary electricity account identifier. This data field should be a required input for any facility that qualifies for a direct allocation of GHG allowances from ARB and that is also a customer of one of California's IOUs."

To accommodate the CPUC's request, ARB could add the following language to Section 95103(a):

> (1) Facility name, assigned ARB identification number, physical street address including the city, state and zip code, air basin, air district, county, geographic location, natural gas supplier name, natural gas supplier customer identification number, an active natural gas supplier service agreement or other financial contract identifier, an active **electric service agreement number or other appropriate financial contract identifier**, and annual billed MMBtu (10 therms = 1 MMBtu).

[OP 09.01 – PG&E]

Response: ARB staff thanks PG&E for their support of the addition of natural gas supplier account information to support the Cap-and-Trade Program. However, at this time ARB staff is not incorporating the suggested regulatory edit to section 95103(a) regarding electric service identifier numbers. The commenter's requested change, and the initially discussed method of sharing such data, could have resulted in the CPUC providing this confidential business information to independently operated utilities. As such, ARB staff decided not to incorporate the suggested language into section 95103(a). Instead, ARB staff continues to work with the CPUC to ensure that the CPUC has sufficient and accurate reported data to return utility auction revenue consistent with AB 32 and the CPUC's proceeding, and in a manner which protects confidential business information.

A-42a. Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.

Comments: [Numerous similar comments were received on this topic. ARB staff has included the full text for some of the commenters to provide context of the issue, and has summarized the remaining commenters' comments.]

Air Products recommends eliminating or narrowing requirements for reporting the nature and reasons for criteria pollutant increase and toxics. [OP 07.04 – AP]

A-42b. Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.

Comments: ARB proposes including Section 95104(e), entitled "Increase in Facility Criteria Pollutant & Toxic Air Contaminant Emissions". This section will require operators to report whether an increase in toxic air contaminants (TACs) or criteria emissions occurred from a facility.

Specifically, the proposed MRR amendment would require facilities to evaluate and report any changes in facility operations or status that may have potentially resulted in an increase in emissions of criteria pollutants or toxic air contaminants in relation to the previous data year and specify the reasons for such increases including any production changes or any regulatory changes or any efficiency changes. While WSPA understands the reason for requesting this information is for Adaptive Management planning and review purposes, we are very concerned with ARB's approach for obtaining this information. As we noted in meetings with ARB, in addition to the numerous concerns about having to track, monitor and report criteria/TAC emission data that is already managed by Air Districts, the regulations as proposed are "one-sided" because they only ask for increases rather than for decreases in emissions. Hence, as written, because only increases are to be reported, ARB and the public will see a skewed and erroneous result.

The requirement to only report increases is problematic. Add to that challenge the fact that, as ARB is aware, many WSPA member facility operations are large and complex in size and scope. These facilities have for over 40 years been subject to air quality regulations and compliance requirements within their respective local air districts. These regulations and reporting requirements track, monitor and maintain air quality permitting, criteria and TAC emissions inventories and monitoring data as required by Federal and State air quality requirements. Much of the data that ARB wishes to receive already exists within local air district programs.

WSPA believes that this massive effort is not efficient for the purposes stated in the Plan. Facilities may be undertaking this resource and time intensive effort to just report that there have been no emission changes. In addition, WSPA believes that the effort may not provide the specific information that ARB hopes to gather. For example, ARB recognizes that changes in emissions can exist from year to year as a result of slight changes in operations that are well within and allowed by air district permits. Further, requiring criteria and TAC emission data information within the GHG MRR reporting program also raises the following concerns:

• How will this information be reviewed and evaluated?

• If a facility expands its operation, obtains all required local, State and Federal air quality permits, and the result is an increase in permitted criteria pollutants, how will the increase in emissions be reviewed by ARB within its Plan?

• Will the information submitted for this new requirement now be subject to a verification or assessment percent accuracy standard?

• Will this information be subject to the penalty provisions in Section 95107?

Finally, the proposed language would require a new extensive tracking, monitoring and reporting system to report criteria and TAC pollutant information to the ARB according to the MRR definitions of facilities, which may differ from district program definitions and requirements. Additionally, air districts have varying time schedules by which they develop their annual criteria and TAC emission inventories as well as specific procedures (i.e., BAAQMD calculates the inventory for facilities).

Recommendation:
Delete Section 95104(e) for all of the reasons explained above. Instead, ARB should work with the regulated community toward identifying a process where information already managed and maintained by Air Districts can be used for ARB Adaptive Management planning purposes.
[OP 08.09 – WSPA]

A-42c. <u>Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.</u>

<u>Comments</u>: We request Section 95104(e) be removed. This section largely duplicates many aspects of the long established programs put in place and administered by either the numerous local Air Districts in California and/or the U.S. EPA. It is unclear why ARB feels it is required or necessary to expand the MRR program to include additional air pollutants, particularly when the regulation is entitled “Mandatory Reporting of Greenhouse Gas Emissions.” Layering on additional and potentially conflicting data collection and recordkeeping and reporting requirements and timelines for the regulated community should not be imposed without additional conversations with stakeholders and a clear outline of ARB’s rationale for this change. Administration and verification of this expanded effort is no small task - unintended consequences of which could include delays in verification or even reduction in the number of positive opinions which could

seriously jeopardize the MRR and Cap-and-Trade programs without commensurate benefit to either. PG&E recommends ARB share its GHG data with local air districts to allow them to form this complete picture. [OP 09.06 – PG&E]

A-42d. Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.

Comments: New requirement to report reasons for increases in pollutants is problematic.
[OP 12.07 – SCPPA]

A-42e. Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.

Comments: Proposed Section 95104(e) is beyond the scope of the MRR. Proposed section 95104(e) could potentially conflict with Air District emission inventory processes. Proposed Section 95104(e) is vague and would impose an unreasonable requirement on affected facilities with little corresponding benefit.
[OP 24.01 – UAL]

A-42f. Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.

Comments: CCEEB has serious concerns about the proposed Adaptive Management language. [OP 29.01 – CCEEB]

A-42g. Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.

Comments: The Proposed Amendments would include a new requirement on facility operators subject to the Cap-and-Trade Regulation relevant to criteria pollutants. This reporting requirement should be rejected. New section 95104(e) (*Increase in Facility Criteria Pollutant and Toxic Air Contaminant Emissions*), would require affected entities to include information in their emissions data report that also addresses:

(1) whether a change in the facility's operations or status potentially resulted in an increase in emissions of criteria pollutants or toxic air contaminants in relation to the previous data year,

(2) the reasons for the change, and

(3) a narrative description of the reasons for the changes.

The ISOR states that this information is needed to support CARB's "*adaptive management monitoring, review, and analysis*."4 M-S-R understands that CARB would like to use the GHG reporting tool as a mechanism to collect this data and further "*assess the potential localized air quality impacts that may result from the Cap-and-Trade program*."5 However, the Proposed Amendment exceeds the scope of the mandate set forth in Health and Safety Code section 38530 to implement regulations to require "*reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program*."6 The information sought regarding criteria pollutants does not fall within the gambit of "greenhouse gas emissions" to be reported and verified under the enabling legislation, and should therefore not be included within the provisions of the MRR.

In addition to being outside the scope of the AB32 reporting mandate, as contemplated, the requirement also imposes additional burdens on reporting entities and provides no new information to CARB. The members of M-S-R already report information regarding criteria pollutants to the local air districts,7 sometimes as frequently as quarterly. CARB, therefore, already has access to the information being sought to assess localized impacts and monitor its adaptive management program. Furthermore, requirements to include the very detailed information in the extensive annual emissions report would require additional staff time and financial resources. This is especially problematic in the context of annual verification of the MRR report, wherein the reporting entities will need to expand that scope of the already costly verification to address this additional requirement.

Rather than require further reporting under the existing MRR program, M-S-R urges CARB to coordinate with the local air districts to assess the level of information the agency may already have at its disposal. If, however, it is still determined that CARB must require this extra reporting requirement, all of the information provided pursuant to section 95104(e) should be expressly excluded from the verification requirement. M-S-R understands that staff intends to recommend to the Board that this section not be included in the revised MRR, as urges the Board to accept staff's recommendation and not add additional reporting for criteria pollutants. [OP 31.02 – MSR]

A-42h. <u>Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.</u>

<u>Comments</u>: The ARB Should Clarify That New Section 95104(e) Is Not Subject To A Verification Requirement. The ARB proposes to amend the Mandatory Reporting Regulation ("MRR") to add a new Section 95104(e), which would require covered entities to report increases in facility criteria pollutants and toxic air contaminant emissions. This new section would also require the covered entity to provide a narrative description for the changes. This new provision would expand the scope of the MRR beyond just greenhouse gas emissions, and it is unclear how this new reporting requirement helps the ARB fulfill its responsibilities for monitoring and tracking greenhouse gas emissions under AB 32 (See Cal. Health and Safety Code Sec. 38530). The reporting and monitoring of criteria pollutants has historically been within the purview of local air districts, and any questions about compliance with air permits or changes in criteria pollutant levels are first resolved with the air districts. TID believes that if the ARB requires information on criteria pollutants to fulfill the requirements of AB 32, then it should rely on the air districts to provide this information.

TID is also concerned that a narrative explanation for an increase in criteria pollutants would be difficult to accurately report and verify. This is because changes in criteria pollutants could come from more than one factor and the narrative explanation could be subjective and open to interpretation. Thus, if the ARB nevertheless relies on its authority under AB 32 to require the reporting of criteria pollutants, it should not require verification for Section 95104(e). [OP 33.01 – TID]

A-42i. Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.

Comments: Section 95104(e) ARB is proposing several revisions in the MRR. Of significance is the change to § 95104(e). Emissions Data Report Contents and Mechanism, requiring facilities to include criteria or Toxic Air Contaminants (TAC) emissions in their MRR GHG report. Specifically, the proposed MRR amendment would require facilities to evaluate and report any changes in facility operations or status that may have potentially resulted in an increase in emissions of criteria pollutants or toxic air contaminants in relation to the previous data year and specify the reasons for such increases including any production changes or any regulatory changes or any efficiency changes. Such tracking will significantly increase the burden on food processing operations, requiring additional time, effort, and resources for information that is already managed by the local Air Districts. Currently, even if increases in criteria emissions occur, such increases are already subject to local regulatory monitoring and would have been compliance with the local Air District permitting program; i.e. all such emissions would be legally permitted.

Adding to this concern, ARB staff states “This information will be used to support the Adaptive Management Plan for the Cap-and-Trade regulation.” Food processors, as well as other industry folk, are concerned as to how ARB will use this information.

Overall, CLFP believes this approach to the collection of criteria and TAC emissions data will unnecessarily complicate the current reporting requirements for food processors as well as create a duplicative burden on facility operators given such information is readily available to ARB via the local Air District.

CLFP recommends the Board delete Section 95104(e) for the reasons stated above. Additionally, it is far easier and less burdensome on obligated facilities if ARB requires reporters, pursuant to valid Adaptive Management regulations, to work with the Air District’s to get the information they may need for purposes of this program. Therefore, CLFP recommends the ARB work with the regulated community toward identifying a process where information already managed and maintained by Air Districts can be used for ARB Adaptive Management planning purposes." [OP 36.01 – CLFP]

A-42j. Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.

Comments: Reporting of increased facility criteria pollutant and toxic air contaminate emissions: this provision should be revised to apply to increases in greenhouse gas emissions only. [B 01.05 – LADWP]

A-42k. Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.

Comments: Remove requirement to report increases in toxic and criteria emissions. [B 02.02 – SU]

A-42l. Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.

Comments: Commenter in board meeting supports proposed 15-day change for removing criteria pollutants and toxics reporting. [T 01.03 – SCPPA]

A-42m. Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.

Comments: Commenter in board meeting supports proposed 15-day change for removing criteria pollutants and toxics reporting. [T 06.02 – MSR]

A-42n. Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.

Comments: Commenter in board meeting supports proposed 15-day change for removing criteria pollutants and toxics reporting. [T 10.02 – WSPA]

A-42o. Modify or Remove Requirements in Section 95104(e) Which Requires Reporting of Changes in Criteria and Toxic Emissions.

Comments: Commenter in board meeting supports proposed 15-day change for removing criteria pollutants and toxics reporting. [T 13.01 – CC]

Response**:** (this response effective for comments A-42, a-o above)
Based on stakeholder input, ARB staff has modified this proposed provision of the regulation to only require identification of annual increases in greenhouse gas emissions, which requires minimal reporting effort. ARB staff believes that these 15-day changes address all of the commenters' concerns.

A-43. <u>Clarification for Facilities That Generate Their Own Thermal Energy And Uses the Energy Within the Facility</u>

<u>Comment</u>: Emissions Data Report Contents & Mechanism. ARB added amendments in Section 95104(d)(4) requiring that if a facility's boundary includes more than one cogeneration system, boiler or steam generator and each system produces thermal energy for different end users or on-site processes and operations, the facility will be required to report the disposition of generated thermal energy by unit/system or by group of units with the same dispositions and by the type of thermal energy product provided. Based on WSPA's understanding, the requirement for an operator to report the disposition of generated thermal energy by "unit/system or by group of units" is defined as a group of units (e.g. cogeneration turbines) that are located at one facility location of which the reporting of thermal energy that goes to a single third party can be reported as a single unit. For example, if there is a cogeneration unit with 3 gas turbines and the generated thermal energy is sold to a single third party operator (i.e.: a utility) the data from all three turbines can be combined and reported as a single data.

In addition to referencing "particular end-user" ARB also requires the reporting of the disposition of thermal energy for "on-site industrial processes".

Recommendation
As stated in our earlier comments, WSPA recommends ARB clarify that for reporting of thermal energy for "on-site industrial processes" the total amount of thermal energy can be reported in total if the total thermal energy is used by the same facility. For example, if a refinery operates a cogeneration unit on-site and the thermal energy produced by the cogeneration unit is used by the same on-site refinery, the refinery can just report the total amount of thermal energy that is used within its facility boundary.

In addition, ARB should provide workshops/training to reporters to ensure there is a clear understanding of both the regulatory reporting requirements including the Cal-eGGRT tool for reporting the disposition of thermal energy. [OP 08.10 – WSPA]

<u>Response</u>: The purpose of the proposed amendment to section 95104(d)(4) was to improve the granularity of the reported data for reporting entities with more than one unit configuration by improving upon the unit configurations descriptions in Cal e-GGRT. Consistent with past Cal e-GGRT releases, ARB staff is committed to ensure reporting entities understand the correct method to report in Cal e-GGRT. This includes reporting guidance on the reporting of thermal energy produced by a cogeneration unit situated within the facility boundary of an on-site refinery. Based on this, ARB staff does not believe further changes to this section are needed at this time.

§95105 – Recordkeeping Requirements

A-44. Reference Documents

Comment: ARB proposes adding in the reference “AGA Report No.3 (2003) Part 2”, as a reference document to be used for orifice plate inspection requirements. WSPA believes that API’s “Fuel Gas Measurement document; API Technical Report 2571; First Edition, March 2011” should also be used as a basis for orifice plate inspections. This API technical report compliments the “AGA Report No. 3(2003)” and “ISO 5167-2 (2003)”, and it provides additional guidance for meters in refinery fuel gas service that ensure compliance with MRR metering requirements. Facilities should be able to use this additional reference especially if it provides more appropriate guidance that is consistent with “AGA Report No.3 (2003) Part 2” and “ISO 5167-2 (2003)”.

Additionally, WSPA requests ARB clarify that in the event there is a disagreement with a verifier over an orifice plate inspection based on the referenced fuel measurement documents, the reporter can utilize alternative engineering methods to demonstrate orifice plate accuracy.

Recommendation: WSPA recommend ARB include API’s “Fuel Gas Measurement document; API Technical Report 2571; First Edition, March 2011” that can be used in conjunction with “AGA Report No.3 (2003) Part 2” and “ISO 5167-2 (2003)”
[OP 08.11 – WSPA]

Response: At this time, ARB staff declines to add in the API reference suggested by the commenter. The proposed amendment in section 95105(c)(7)) was made to correct the citation for a previously (and already) incorporated by reference document. ARB staff believes the two citations for orifice plate inspection are sufficient to meet the measurement accuracy requirements in section 95103(k). In instances where there is a disagreement over the method used for an orifice plate inspection, refineries should contact ARB staff to discuss the issue. ARB staff disagrees that a reporting entity can utilize alternate engineering methods to demonstrate orifice plate accuracy to a verifier in cases of a disagreement.

§95110 – Cement Production

No comments received in this section.

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

§95111 – Electric Power Entities

B-1a. Seller Warranty for Specified Power, Section 95111(a)(4).

Comment: Morgan Stanley recommends a slight change to the proposed language in Section 95111(a)(4) which is necessary to make it clear that the job of establishing the qualification of a transaction as "specified" rests with the initial purchaser, who must meet all of the requirements. Unchanged, ARB's proposed language would imply that the initial seller must warrant that the sale qualifies as "specified". As described in more detail in our prior argument, MSCG strongly believes that the seller should have no role in establishing that fact. These slight changes are shown in bold, double underline here:

(4) 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 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. The sale or resale of specified source electricity is permitted among entities on the e-tag market path insofar as each sale or resale is for specified source electricity in which sellers have purchased and sold specified source electricity. ***Starting with the initial purchaser***, each seller ***must*** warrant the sale of specified source electricity from the source through the market path. [OP 01.04 – MSCG]

Response: As suggested by the commenter, the initial seller will have already included a warranty in the form of contract, which will determine whether power can be claimed as specified. Thus, an EPE purchasing specified source power directly from a specified source (not via broker or trading exchange) will have met the seller warranty requirement by contracting directly with the source. Each sale or resale after that initial sale will also need to include some form of seller warranty. As such, ARB staff does not believe the change suggested by the commenter is necessary and declines to make the change.

B-1b. Seller Warranty for Specified Power, Section 95111(a)(4).

Comment: BPA. Regarding 95111(a)(4), ARB has proposed to update this section to "effectively require sellers of specified power to warrant or guarantee that the transacted product is, in fact, specified source electricity from the generation source along each segment in the market path." Regarding 95111(a)(5)(B), CARB states that this proposed change would "establish that asset-controlling supplier power may be reported as either specified or unspecified power depending upon the transaction, for the reason that asset-controlling supplier power can be sold in the market as either specified or unspecified power."

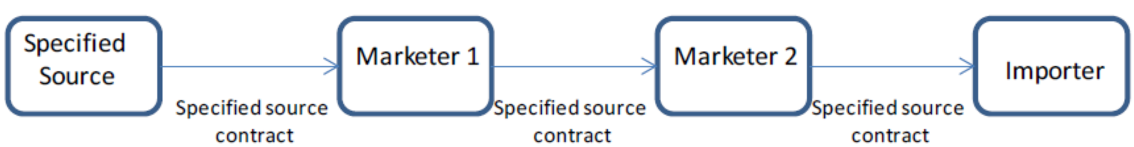
BPA supports the proposed changes to both these sections. As an ACS, BPA regards these changes as related to each other. That is, the change to (a)(4) requires sellers of specified power to warrant or guarantee that what they are selling is in fact specified source power. This principle is then applied to ACS sellers (when selling specified power) through the change to (a)(5)(B), and the new language in (a)(5)(B) makes clear that an "ACS seller controls whether the specified ACS attributes are conveyed with the transaction." Thus, an ACS seller would control whether the product it is selling is specified by choosing whether to provide a warranty or guarantee to that effect to the purchaser.
[OP 18.02 – BPA]

Response: ARB staff appreciates BPA's support on this issue, although ARB staff will consider the seller warranty and seller control proposed changes independently. For response to comments on the seller control see response to comments B-2a-l.

B-1c. Seller Warranty for Specified Power, Section 95111(a)(4).

Comment: J. Aron/Goldman Sachs states that under the current regulations for specified source power, the guiding principle is that there must be a contract with the specified source that identifies it as the source of supply, as opposed to a purchaser that is randomly matched up with a specified source on in an unspecified power exchange market. One challenge in implementing this principle arises when an entity purchases from a specified source and then resells to another entity. The concern is that a purchase from a specified source on an exchange (i.e. one that was not made under a specified source contract) not be resold as specified power. The proposed seller warranty language appears to address this concern by requiring each seller to warrant that it is, in fact, selling specified power. However, it is not clear if the language actually intends to go further and introduce new requirements on what can qualify as specified power.

By way of an example, consider the following illustration, where a Specified Source sells to Marketer 1, who then resells to Marketer 2, who in turn resells to the eventual Importer. In order for the Importer to claim the power as specified power, it is understandable that there must be a verification that each sale in the market path or chain was made pursuant to a specified source contract.



One would expect that the Importer would be required to document its purchase from Marketer 2 as one that was made under a specified power contract. Similarly, Marketer 2 would need to document that its purchase from Marketer 1 was made under a specified power contract and Marketer 1 (the initial purchaser) would document that it purchased power from the specified source pursuant to a specified source contract. The language requiring a “seller warrant” would appear to address this issue. However, it is not obvious why the original seller from the specified source needs to make such a warrant unless there is some other significance to the language on seller warrants. Would the Marketer 1 purchase from the Specified Source under a specified source contract that clearly lists the Specified Source as the source of supply not qualify, unless the term “seller warrants” appears in the contract?

If the language on seller warrants is intended to introduce some new requirement for what product can qualify as specified power, it would help to more clearly state the reasons for the change, recognize it as a change, fully understand its implications and only apply it prospectively. [OP 11.01 – JA/GS]

Response: ARB agrees with the JA/GS inclination on this issue, that the original seller will have warranted the sale through the specified source contract, which would satisfy the ARB seller warranty provision. The term ‘seller warrants’ is not a required contract term, and the original seller need not provide an additional separate warrant because the specified source transaction itself will effectively provide the warranty as the power was procured from the generation source by the buyer pursuant to ARB requirements.

B-1d. Seller Warranty for Specified Power, Section 95111(a)(4).

Comment: TransAlta suggests the following modification to the proposed regulatory language in section 95111(a)(4):

For power contracts executed after December 31, 2013, the sale or resale of specified source electricity is permitted among entities on the e-tag market path insofar as each sale or resale is for specified source electricity in which sellers have purchased and sold specified source electricity, such that each seller warrants the sale of specified source electricity from the source through the market path. [OP 05.01 – TA]

Response: See response to comments A-29a-f. For the reasons stated in that response, ARB staff declines to make the proposed change.

B-1e. Seller Warranty for Specified Power, Section 95111(a)(4).

Comment: SCE supports ARB staff’s attempt to clarify the regulations governing resale of specified source electricity by adding language in Section 95111(a)(4) of MRR. However, SCE suggests that the ARB further amend the MRR to clarify that the electricity importer of any “resold” specified source electricity (i.e., contracts to purchase specified source electricity from entities that are not the generation-providing entity of the source) will only be required to provide proof of a contract with its direct seller in which (1) the seller warrants the sale of specified source electricity from the facility, and (2) the importer has the contractual right to obtain from the seller additional documentation certifying that the electricity was transacted as specified from the source through the market path, as may be required for verification. SCE recommends that the

ARB add the following language to Section 95111(a)(4) in order to clarify this distinction for market participants:

"The sale or resale of specified source electricity is permitted among entities on the e-tag market path insofar as each sale or resale is for specified source electricity in which sellers have purchased and sold specified source electricity, such that each seller warrants the sale of specified source electricity **<u>and is able to provide supporting documentation that the electricity was transacted as specified source electricity</u>** from the source through the market path." [OP 21.02 – SCE]

<u>Response</u>: ARB appreciates SCE's support on this issue. However, ARB declines to make SCE's proposed edits. Staff believes that the proposed change is unnecessary for implementation of this provision. The requirements already imply that supporting documentation is needed for specified source claims.

B-1f <u>Seller Warranty for Specified Power, Section 95111(a)(4)</u>.

<u>Comment</u>: Powerex appreciates that, under the proposed amendment to MRR § 95111(a)(4), ARB has clarified that "The sale or resale of specified source electricity is permitted among entities on the e-tag market path insofar as each sale or resale is for specified source electricity in which sellers have purchased and sold specified source electricity, such that each seller warrants the sale of specified source electricity from the source through the market path." But that may not go far enough to properly connect written power contracts for specified power with the direct delivery of electricity to California.

In many cases the generator of the specified power is not the importer into California. By adding a predefined field into the e-tag associated with delivery of the specified power contract, all parties in both the contractual chain and the delivery chain would have clear evidence that the generation was intended to be specified. Powerex recommends that a "GHG token" with the ARB ID of the facility be placed in the generation line of the physical path of the e-tag (a direct analog to the "RPS_ID" used by the California Energy Commission for verifying RPS delivery) to clarify that the direct delivery (the e-tag) is associated with a written power contract for specified power. See the table below. Verifiers then could add the spot checking of GHG tokens on the e-tags to the specified power verification process to ensure that a direct delivery claim was associated with clear, written power contracts.

First Line of the Physical Path Table on the E-Tag Power Including GHG Misc/Token Physical Path							
CA	TP	PSE	POR	POD	Sched Entities	Contract	**Misc (Token / Value)**
BA		**Generating Entity 1**	Source Point 1				**GHG (Source1 CARBID)**

Applying this e-tag requirement, coupled with the industry's current e-tag approval/denial processes, would further enable sellers of specified power to warrant unambiguously that the power is indeed specified and thus provide a significant aid to the verification process. This would also compel parties to ensure that the buyer and seller both agree on the product transacted prior to energy delivery. [OP 26.06 – PX]

Response: ARB staff disagrees with Powerex's characterization of the seller warranty proposal. ARB staff notes that there is broad support for the proposal among stakeholders. The seller warranty proposal was originally formulated in response to stakeholder request for guidance on how to claim short term transactions as specified source power. Although the "GHG token" approach described by Powerex could contribute more to the documentation process, we are not inclined to mandate it without further stakeholder engagement on this topic.

B-1g. Seller Warranty for Specified Power, Section 95111(a)(4).

Comment: Powerex, in oral comments before the Board, reiterated support for points made in its written comments, including requirements for written power contracts for all specified source claims, associated tagging, and seller control. [T 02.02 – PX]

Response: ARB notes that Powerex did not raise any issues that were not already addressed in its written comments. Accordingly, see the response to comments B-1f, B-2j and B-4c.

B-1h. Seller Warranty for Specified Power, Section 95111(a)(4).

Comment: WPTF requests that ARB staff provide additional clarity on documentation needed for substantiating the sale of specified source electricity from the generation source through the market path. Our concerns relate to two issues. First, as WPTF has previously noted, it is not standard market practice to provide written confirmations for electricity transactions with duration of less than one week. Stakeholder concerns about potential ambiguity as to whether verbally confirmed short-term transactions are specified or not, should be reduced going forward as market participants build conditions into contracts to explicitly address requirements for sale of specified power. For this reason, WPTF recommends that CARB accept electronic writing confirmations of short-term transactions. If electronic writing will not be considered acceptable, we request that CARB clearly indicate what is required for documenting specified short-term transactions.

Second, WPTF seeks CARB guidance on whether, in the case of the resale and import of specified electricity, documentation of the entity with marketing control of a facility (i.e. the GPE) may be required for verification. For instance, consider Entity A who is an exclusive marketer for a facility, and sells specified power off that facility to Entity B. If Entity B imports this power to California and reports it as specified, will documentation that Entity A is the exclusive marketer for Facility A be required (in addition to documentation of the specified contract between Entity A and Entity B) in order for Entity B to report the power as specified? If the answer is yes, then WPTF would be concerned about requiring GPEs to disclose commercially sensitive information to buyers further down the market path. While this may not be an issue for simple power contracts, it would certainly be a concern for more complex structured or tolling agreements. We would therefore recommend that CARB provide GPEs with the option to provide any necessary documentation required to substantiate a buyer's claim of specified source electricity directly to a verifier. This would avoid the need for a GPE to disclose commercially sensitive information down the market path. [OP 02.05 – WPTF]

Response: ARB staff disagrees with WPTF on the seller warranty issue. ARB staff believes that a specified source contract between buyer and original seller effectively establishes the warranty because the power was procured straight from the generation source pursuant to the reporting requirements. However, for resale transactions, resellers are obligated to warrant that a particular transaction is specified by offering some sort of documentary proof of contact for verification purposes.

B-2a. Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)

Comment: TransAlta does not support the proposed updates in section 95111(a)(5)(B), specifically based on the explanation of these changes outlined in the ISOR. ARB's expectation that the seller controls whether the specified attributes are conveyed with the transaction does not align with other parts of the regulation which denote specification. In the ISOR, ARB notes that the ability of a seller to market specified power is analogous to selling power and RECs. In such a transaction, ARB feels the specified source themselves would determine whether the specified ACS attributes convey in a transaction for specified ACS power. Thus, in order to claim certain types of specified power, EPEs must provide some evidence that the ACS attributes were in fact conveyed at each point along the market path shown on the eTag.

The concept that specified source transactions are like RECs is not appropriate. RECs can be unbundled from a source, and used as standalone commodities for compliance. Further, the electric power entity is required under the Regulation to 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. A power contract for a specified source is a contract that is contingent upon delivery of power from a particular facility, unit, system, or asset controlling supplier's system that is designated at the time the transaction is executed. The Regulations do not reference any requirement for an ACS or other type of specified source owner to convey any additional "attributes" to solidify specified source transactions. In addition to the explanation in the FSOR being inconsistent with the regulations, this modification also places an additional layer of regulatory risk and administrative burden on power importers, who must decipher what qualifies as a satisfactory "warranty" to convey these specified attributes. A move in this direction and away from the concept of contingency only adds unnecessary risk to the first deliverer. [OP 05.04 – TA]

Response: ARB staff prefaces this response by stating that there are two types of seller control: (1) form of sale, and (2) product designation. In the first case, the seller has control over whether the sale is bilateral, brokered, or via market. In the second case, the seller would have control over how the product is designated, e.g., as either a specified or unspecified power sale. The seller control proposal for asset controlling supplier power, that was presented for stakeholder review and comment in the ISOR staff report rationale for section 95111(a)(5)(B), was a product designation type of seller control. It was presented for stakeholder review and comment because at least one ACS had at least on an interim basis operationalized this practice.

Based on stakeholder comments, and after further assessing the proposed 45-day language, ARB staff has withdrawn the seller control proposal for asset controlling supplier power that was presented for stakeholder review and comment in the ISOR staff report rationale for section 95111(a)(5)(B) because ARB staff determined it is inconsistent with our overall contract-based framework for reporting imported power under section 95111. Although the characterization of the regulatory language was withdrawn, the proposed language in section 95111(a)(5)(B) remains unchanged, as shown here:

(B) ~~Report delivered electricity as specified and not as unspecified;~~Report asset-controlling supplier power that was not acquired as specified power, as unspecified power;

The broader section of 95111(a)(5) sets forth requirements for the reporting of imported electricity supplied from asset-controlling suppliers. The proposed update in section 95111(a)(5)(B) clearly establishes that an electric power entity may only claim asset-controlling supplier power as a specified source, when buyer and seller have agreed on a specific specified source prior to contract execution. However, for asset controlling supplier power that was acquired as unspecified power, where the power source was not designated prior to contract execution, the power must be claimed as unspecified. In the ISOR rationale, we stated that:

"…this change is necessary to establish that asset-controlling supplier power may be reported as either specified or unspecified power depending upon the transaction, for the reason that asset-controlling supplier power can be sold in the market as either specified or unspecified power. In order to claim asset-controlling supplier power as specified, the requirements to claim a specified source of electricity must be met because a 'specified source also means electricity procured from an asset-controlling supplier recognized by the ARB,' per Section 95102(a). Asset-controlling supplier power would be claimed as unspecified power in the event that "the source of electricity … is not a specified source at the time of entry into the transaction to procure the electricity," per section 95102(a)."

However, ARB now withdraws the seller control description provided in the ISOR rationale as shown below in strikethrough, for the reason that it is inconsistent with our overall contract-based framework for reporting imported power under 95111.

~~*It is ARB's expectation that the ACS seller controls whether the specified ACS attributes are conveyed with the transaction. For example, a renewable energy seller determines whether the renewable energy credits (RECs) convey in a transaction for specified power. Similarly, the ACS would determine whether the specified ACS attributes convey in a transaction for specified ACS power. Thus, in order to claim specified ACS power, EPEs must provide some evidence that the ACS attributes were in fact conveyed at each point along the market path shown on the eTag.*~~

ARB agrees with TransAlta, that the seller control proposal does not align with other parts of the regulation which denote specification. ARB has withdrawn the proposed interpretive approach, as described above.

B-2b. Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)

Comment: WPTF states that the MRR has evolved over the past year towards enshrining the principle that the generation owner controls whether the electricity from that source is sold as 'specified' or not. This is most clearly articulated in the explanation provided in the Initial Statement of Reasons (ISOR) that an Asset Controlling Supplier (ACS) seller "controls whether the specified ACS attributes are conveyed with the transaction ." It is also implicit in the proposed new requirement in Section 95111(a)(4) for "each seller to warrant the sale of specified source electricity from the source through the market path." WPTF supports the principle that the generation owner controls whether electricity sold is specified, but is concerned that it is inconsistently applied in several areas of the regulation.

First, both definitions of "Generating Providing Entity" (GPE) and "Specified Source" distinguish between entities that control electricity from a generator and entities that have a power contract to procure electricity from that generator, but differ in how they characterize entities with control of generation. The specified source definition recognizes only those entities having "full or partial ownership in the facility or unit", whereas the GPE definition also recognizes entities that are either "party to a contract for a fixed percentage of generation, party to a tolling agreement with the owner, or exclusive marketer."

This distinction is important because entities with control of a generator have the inherent right to control whether electricity is sold as specified, whereas contract holders must demonstrate that they have procured that electricity as specified. WPTF considers that determination of whether an entity is considered to have direct control over electricity from a facility or unit, versus a power contract for procurement of that electricity, should be dependent on whether that entity has authority *to dispatch or market electricity off that source.* The categories of entities that meet this test would be a) entities with full or partial ownership of a facility, b) exclusive marketers of a facility, unit or system, and c) entities with tolling contracts. Facility operators should not be deemed to meet this test, because although they are responsible with the day to day operations of the facility, they do not typically have authority to market power from the facility.

Similarly, fixed percentage contracts also do not meet this test. Fixed percentage contracts or 'slices', are commonly used for sale of generation from hydro-electric systems to accommodate variation in facility generation due to weather and legal requirements under federal and state operating laws. These contracts were not intended to automatically make the transacted electricity specified – rather the environmental attributes associated with the electricity generation are typically sold as optional add-on. To define buyers of slice contracts as GPEs is thus incompatible with the principle that the generation owner controls whether electricity is sold as specified. It would also force a buyer of a slice product who has not purchased the associated environmental attributes into the untenable situation of either violating the reporting regulation (by reporting that power as specified) or violating contract terms (by reporting power as specified).

Second, the definition of a "power contract" does not capture the seller's intent to sell power as specified, but rather inappropriately suggests that designation alone of a facility, unit, system or ACS system is sufficient to render a transaction specified. As CARB has correctly recognized in the ISOR, electricity sold by an ACS from its system may be sold as either specified or unspecified power, *depending on the intent of the ACS seller*. Thus it is not the designation of the source alone (in this case, the ACS system) that makes a transaction specified, but rather the designation of the source plus the seller's intention to sell that power as specified.

WPTF agrees with this principle and urges CARB to apply it consistently for all electric power entities and all resources. We note that there are commonly used contract models, such as the WSPP Service Schedule B, that would meet the test that of being contingent upon delivery from a particular source, but that are used for reasons completely independent of carbon. (Service Schedule B for example is used to transact non-firm power without limited financial damages.) For CARB to automatically consider these types of contract to be specified, without also requiring evidence of the seller's intent to sell that electricity as specified, would deprive the owner of that generation of control of the specified source attribute and would interfere with the normal operation of power markets.

To rectify these inconsistencies, WPTF recommends that CARB:

- Modify the definition of GPE so that it correctly refers to those categories of entities with rights to *market* the electricity from a facility or unit (i.e. owners, toll holders and exclusive marketers). We also suggest deleting the phrases "that is either the electricity importer or exporter" and "specified source" because they are unnecessary and addressed elsewhere - section 95111(a) requires GPEs that are importers and exporters to report associated power as specified and the definition of specified source establishes when electricity from a facility or unit is specified.
- Revise the Specified Source definition to use the term "generation providing entity" in order to make the two definitions consistent.
- Modify the definition of "power contract for a contract" to require both designation of a facility and clear intention of the seller to transact that power as specified. This could be demonstrated via a seller warranty of the sale of specified power, as

required under 95111(a)(4), or through other means, such as the conveyance of environmental attributes.
[OP 02.01 — WPTF]

[Note from ARB staff: WPTF's proposed edits to the GPE, Power Contract, and Specified Source definitions are addressed under parts A-16, A-19, and A-20.]

Response: ARB staff disagrees with WPTF on the seller control proposal, as it does not align with other parts of the regulation. ARB staff has withdrawn the proposed approach. See Response to comment B-2a.

B-2c. Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)

Comment: In prepared comments before the Board on the 'specification of imported electricity' [seller control issue], WPTF considers that, as a matter of principle, the owner of a low-emission generation source should control whether electricity from that source is specified, and should appropriately capture the economic benefit of avoided greenhouse gas emissions. This principle is fundamental to the successful operation of a cap and trade system, which relies on a carbon price signal for generator dispatch and investment.
[B 03.02 – WPTF]

Response: See Response to comments B-2a and B-2g below.

B-2d. Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)

Comment: WPTF testified the same comments as above, in person at the board hearing. [T 12.02 — WPTF]

Response: See Response to comment B-2a.

B-2e. Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)

Comment: Morgan Stanley states that the crux of their concern, and the main point of disagreement on this issue, centers on this quote from the Staff Report: Initial Statement of Reasons, "It is ARB's expectation that the ACS seller controls whether the specified ACS attributes are conveyed with the transaction." To support this viewpoint, the Staff Report goes on to make an analogy with RECs. It is the strongly held view of MSCG that the analogy is inapposite, and that the "expectation" described above is not required to ensure the environmental integrity of the program. Instead, it arbitrarily allocates benefits between market participants (compliance entities that are importers and ACS sellers). Furthermore, indirectly, this allocation of economic value comes at the expense of California consumers, to the extent that it results in higher prices paid by importers who either are compliance entities, or who may sell power to entities who ultimately deliver power to end-use consumers (Investor Owned Utilities, Municipal

Utilities, etc.). For these reasons, MSCG strongly urges the Board to reconsider the proposals that stem from this inappropriate assumption about control of attributes.

MSCG is concerned with clarifications and amendments that enshrine control of whether or not a purchase from an ACS is a "specified" purchase to the sole discretion of the ACS. ARB has developed a clear set of requirements for whether or not a particular import meets the criteria for being from a specified source. At the core, these requirements are (1) written contract, (2) identification of the resource in the contract, (3) direct delivery to California. Further, with regard to an ACS specifically, ARB has proposed an amendment in the definitions (#20) that states unambiguously that "Asset Controlling Suppliers are considered specified sources". We believe that the three core criteria and the clarification proposed in the definition are entirely appropriate with regard to the determination of whether or not a transaction can be considered and reported as "specified". Yet part of the proposed amendments includes the proposed "clarification" that an ACS controls whether or not a sale is specified. This additional criterion provides absolutely no improvement to the environmental integrity of the cap and trade program, and contradicts other parts of the regulations. Conversely, it can be construed as unwarranted interference in negotiating and contracting activities outside the state of California. Furthermore, it swings the determination of whether or not power can be reported as "specified" based solely on whether or not the seller deigns to use the word "specified", rather than on any intrinsic aspect of the underlying electricity being contracted for or the type of transaction used. Last, but not least, granting this type of arbitrary overlordship over how a transaction is reported to ARB to the seller, rather than to the buyer/importer, has the potential to raise the cost of power to California consumers.

To see why this is so, consider the following transaction. Buyer X negotiates a purchase from an ACS. The transaction will have a written contract, and Buyer X intends to direct deliver the power to California. All of the details are negotiated except the price. For this final detail, the ACS says "if you want us to say the transaction is specified, the price is an extra $6/MWh." Regardless of which option Buyer X elects, the 3 core requirements of a specified source purchase will have been met. The physical dispatch of the ACS' system will be unchanged. In what way will the ability of the ACS to arbitrarily charge a premium for the "service" of stating for the record that the purchase is specified, improve the environmental integrity of the program? Clearly, the answer is that it will not. Therefore, what rationale can ARB have for interfering in commercial negotiations where no issue of environmental integrity is at stake? Even worse, why would ARB want to take such a position when it ultimately, if indirectly, takes money out of the pockets of California consumers?

Last but not least, granting this kind of ability to arbitrarily deem some transactions to be specified and others not, especially when combined with the new "path out" ability to deem some ACS power sales as "surplus", facilitates Resource Shuffling - - the physical dispatch is unchanged, but the degree of emissions attributed to California consumption varies at the whim of the seller. Therefore, if anything, granting an ACS the ability to arbitrarily designate transactions as specified or not degrades the environmental integrity of the program.

MSCG will speculate that some of the concerns that may have driven this decision are valid, although we believe that the solution is misguided. Issue one is whether or not power bought from an ACS on an exchange can be treated as specified. We agree with the philosophy that this type of transaction does not meet the criteria for a specified transaction regardless of how it is e-tagged. However, it is not necessary to give an ACS (or any other type of seller, for that matter) arbitrary control of designation of transaction type to make this clear. The exact wording used could be constructed in many ways, but the basic concept would simply be something like “transactions originally consummated via exchange, broker or other intermediary, where the seller and buyer do not initially know who they are contracting with, do not meet the criteria for “specified source” transactions regardless of how they are tagged or delivered to California”. [OP 01.01 – MSCG]

Response: ARB agrees with the MSCG contention that the seller control characterization is inconsistent with other MRR requirements which base the classification of power claims on the specific features of the transaction itself, not on a potentially arbitrary seller designation. See Response to comment B-2a for further explanation.

B-2f. Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)

Comment: PacifiCorp states that notwithstanding the jurisdictional limitation arguments set forth in its comments, it respectfully suggests that CARB should revisit the ACS designation and rules in light of the ARB goals articulated in the proposed rulemakings and 2013 workshops. Specifically, ACS entities seem to be able to de-designate themselves as a specified source, and sell unspecified rather than specified power, in circumstances in which the generation providing entity of a specified source would not be able de-designate itself as a seller from a specified source with a mandatory emissions factor.

Currently, there are two ACS registered entities. PacifiCorp encourages ARB to eliminate ACS entities and require all parties to sell from a specified resource to obtain an emission factor that is not the default rate. To do otherwise results in resources outside of California that give a free premium pricing option to ACS entities that will impact overall wholesale pricing in the Western Electric Coordinating Council.

The ability of ACS entities outside of the state of California to determine whether the identical energy scheduled under identical circumstances does or does not have specified source characteristics or is unspecified power creates concerns and implications on wholesale pricing outside of California. PacifiCorp urges ARB to consider the elimination of ACS as a designation and implement stand-alone contracts, or pools of resources, consistent with the specified resource requirements, to minimize disruption in wholesale markets in the WECC. [OP 15.02 – PC]

Response: ARB staff shares the PacifiCorp concern with the seller control characterization, and ARB has withdrawn the interpretation described in the 45-day ISOR. Instead of taking issue with the proposed concept, PacifiCorp has assumed that the proposed feature was an inseparable component of the ACS program, which could explain why PacifiCorp urged ARB to "consider the elimination of ACS as a designation and implement stand-alone contracts, or pools of resources, consistent with the specified resource requirements, to minimize disruption in wholesale markets in the WECC." Instead, with the elimination of the seller control characterization, ARB staff believes it has addressed the concern, as PacifiCorp has not heretofore taken such issue with the ACS program. See Response to comment B-2a for further explanation.

B-2g. <u>Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)</u>

<u>Comment</u>: BPA states that the proposed change to 95111(a)(5)(B) would "establish that asset-controlling supplier power may be reported as either specified or unspecified power depending upon the transaction, for the reason that asset-controlling supplier power can be sold in the market as either specified or unspecified power." BPA considers these changes related to the seller warranty in 95111(a)(4), that would "effectively require sellers of specified power to warrant or guarantee that the transacted product is, in fact, specified source electricity from the generation source along each segment in the market path." BPA supports the proposed changes to both these sections.

As an ACS, BPA regards these changes as related to each other. That is, the change to (a)(4) requires sellers of specified power to warrant or guarantee that what they are selling is in fact specified source power. This principle is then applied to ACS sellers (when selling specified power) through the change to (a)(5)(B), and the new language in (a)(5)(B) makes clear that an "ACS seller controls whether the specified ACS attributes are conveyed with the transaction." Thus, an ACS seller would control whether the product it is selling is specified by choosing whether to provide a warranty or guarantee to that effect to the purchaser.

The principle of allowing a seller to control its own product is appropriate because, at its core, the California Cap & Trade and MRR program (in the context of the electricity sector) is intended to provide a market mechanism that encourages investment in, and dispatch of, low-carbon resources. To achieve this, sellers must be able to realize the carbon-related economic benefits of their power by having the ability to choose when to convey such benefits. In this vein, BPA agrees with the August 15, 2013, comment of Powerex that "Allowing buyers to acquire the carbon-related economic benefits of low emission factor power without consent from the seller effectively nullifies the very price signals upon which the Program is founded."

To convey the market-driven signals that CARB is attempting to send, the MRR has recognized a fundamental principle: The right to claim power as "specified" is a negotiated term of a transaction between buyer and seller. Specifically, the MRR makes clear that a "written power contract" is to be used "for the purposes of documenting specified versus unspecified sources" and it defines a contract for a specified source as 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*." By placing importance on the "designat[ion] at the time the transaction is executed," the MRR makes specified source status a material term of a transaction that must be agreed upon by the parties. CARB's online guidance reiterates this concept: "EPEs need not contract directly with an ACS in order to claim ACS power so long as the original buyer and any subsequent buyers and sellers showing in the NERC e-tag market path *utilize a specified power contract to convey the right to receive ACS power*." Thus it is clear that the parties must utilize a contract that specifically shows that their intent was "to convey the right to receive ACS power."

To accomplish this, a seller (whether from a low-emission or high-emission resource) must have the ability to choose whether or not to convey that right. Without that choice, the right to claim power as "specified" will automatically pass to buyers without any negotiation process. The point is not to grant sellers "arbitrary lordship" over the value but, rather, to allow parties to enter a discussion about value and to mutually agree on what is appropriate. If sellers are not permitted to choose whether to convey their power as "specified," then that right unilaterally shifts to buyers and thereby prevents the market from determining the appropriate value of "specified" power. This would destroy CARB's already-established principle that "the right to receive ACS power" is a material term of a contract that the parties must agree upon and "designat[e] at the time the transaction is executed."

Accordingly, to ensure a level playing field in the market, the concept of seller choice (as embodied in the written power contract) should apply equally among sellers. One way to accomplish this is proposed by the comments of Western Power Trading Forum (WPTF), which describe certain changes to the regulations. BPA supports the general premise of WPTF's comment, namely, that CARB should consistently apply the principle of seller choice for all electric power entities and resources.

BPA also notes CARB's statement in the ISOR that "in order to claim specified ACS power, EPEs [Electric Power Entities] must provide some evidence that the ACS attributes were in fact conveyed at each point along the market path shown on the eTag." The phrase "some evidence" is vague. BPA presumes that such vagueness may be intentional because CARB may need to evaluate on a case-by-case basis whether an EPE that brings power into California has proof that the power is in fact specified. For example, in the past BPA's trading floor has provided its purchasers with a "BPA ACS specified confirm" to serve as a showing that what was conveyed was in fact specified power. It is BPA's understanding that such a confirm would meet the "some evidence" requirement that CARB would look for from an EPE bringing specified power into California. Apart from its trading floor power sales, BPA also makes various other types of contract sales for both power and load service. If an EPE wishes to claim these as "specified" for purposes of CARB's regulations, CARB will need to work with EPEs to clarify the type of documentation needed.

Lastly, BPA recommends deleting the following sentences from the ISOR's rationale for the proposed updates to section 95111(a)(5)(B):

For example, a renewable energy seller determines whether the renewable energy credits (RECs) convey in a transaction for specified power. Similarly, the ACS would *determine whether the specified ACS attributes convey in a transaction for specified ACS power.*

The comparison to RECs is not needed to explain CARB's rationale. Moreover, it is confusing because RECs are a tradable commodity that can be bought and sold separately from the power that they are generated with. Assuming the sentence discussing RECs is deleted, CARB should also delete the sentence that follows it, beginning with "Similarly." Without the REC sentence, there is no need for this sentence. Moreover, this sentence is repetitive of the earlier sentence that states: "It is ARB's expectation that the ACS seller controls whether the specified ACS attributes are conveyed with the transaction." BPA agrees with this proposition, but it is not necessary to state it twice. [OP 18.01 – BPA]

<u>Response:</u> ARB staff disagrees with BPA in its arguments in support of the seller control characterization. BPA argues that the seller control characterization is related to the proposed seller warranty provision in section 95111(a)(4). Although a relationship between the two provisions can be constructed, ARB staff considers these provisions to be independent for purposes of this rulemaking, as each provision is designed to address a separate issue. In this rulemaking, ARB will have better aligned ACS and specified source claims; however, the seller control approach supported by BPA would, in fact, create a severe misalignment. If ACS entities were granted the ability to designate power as specified or unspecified with no objective basis for the designation, specified source entities would arguably seek the same ability, and there is no reasonable basis to grant this ability only to ACS entities and not also to specified source entities. And, granting such ability to specified source entities would create an untenable regulatory framework for GHG reporting. For specified source entities above the default emission rate, such a designation may lead to resource shuffling, to the extent an entity opted to not convey its high carbon emission attributes as part of the transaction. ARB staff considers the seller control characterization to be an untenable and unacceptable market design feature. See Response to comment B-2a for further explanation.

B-2h. <u>Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)</u>

<u>Comment</u>: J. Aron/Goldman Sachs briefly addresses the seller control issue by stating that, "assuming the inclusion of the language … [on the seller warranty issue] is intentional and not an error, it would help to clarify the applicability of the new concept of conveyance of ACS attributes." [OP 11.02 – JA/GS]

<u>Response</u>: See Response to comment B-2a.

B-2i. <u>Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)</u>

<u>Comment</u>: In the proposed amendments, ARB staff propose adding language to Section 95111(a)(5)(B) of the MRR, to specify that the reporting entity must "Report asset-controlling supplier power that was not acquired as specified power, as

unspecified power." SCE supports ARB staff's recognition that transactions occur in the market in which electricity may be purchased from an asset-controlling supplier ("ACS") that is not specified, and that imported electricity which is not designated as specified power at the time of transaction should be reported as unspecified power. This revision to the MRR should be adopted by the ARB. The connection of the ACS emission factor to the designation of the imported electricity as specified power at the time of transaction better aligns with the decision-making process used by power traders in the market. Such power traders may assume that all imported power for which the seller is unknown will be reported using the default emission factor. For instance, if the seller's identity is unknown at the time of the transaction, as is the case with transactions executed on the Intercontinental Exchange, the buyer will likely assume that all imported power will be reported using the default emission factor. Similarly, if a buyer agrees over the phone or instant messaging to buy unspecified power from an ACS, that agreement should align with the emission factor reported for the transaction, regardless of the source listed on the e-tag for the deal. [OP 21.03 – SCE]

Response: ARB staff appreciates SCE's support. ARB staff agrees with SCE that some ACS entities have the ability to transact both specified and unspecified power, and that imported electricity which was not designated as specified power at the time of transaction must be reported as unspecified power. ARB is pleased to hear that the proposed language and current interpretation "better aligns with the decision-making process used by power traders in the market." ARB staff considers our preferred approach well aligned with the reporting program as well. See Response to comment B-2a for further explanation.

B-2j. Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)

Comment: Powerex states that ARB's proposed amendments to MRR Section 95111(a)(5)(B) are necessary. Powerex supports ARB's proposed amendments to MRR § 95111(a)(5)(B). The proposed amendment is necessary since power already may be supplied by an ACS as either specified or unspecified, depending on whether the contract is contingent upon delivery of power from the ACS system. This is no different than the ability of individual resource owners to sell "specified source" power by committing to deliver power from the unit designated at the time of the transaction, or to sell unspecified power and making no such commitment. Powerex believes confusion has arisen due the definition of the Asset Controlling Supplier itself as a specified source (despite many other aspects of the Regulation that suggest the contrary). Powerex believes that modifications to MRR § 95102(432) and § 95102(20) are essential to eliminate this confusion, and proposes specific language herein. (See Section 1(e) below.)

Powerex supports ARB maintaining its existing approach to defining "specified" power (from ACS entities and from non-ACS entities alike) and its two key requirements: (1) a written power contract committing the seller to deliver the power from a designated source, and; (2) a NERC e-Tag verifying that the power was, in fact, delivered from the designated source to a California Balancing Authority.

ARB Should Continue to Require a Written Power Contract for Specified Power. The role of a written power contract is central to determining whether power can be claimed from a specified source, as the very definition of "power contract" in MRR § 95102(351) makes clear (emphasis added):

> "Power contract" or "written power contract," as used for the purposes of documenting specified versus unspecified sources of imported and exported electricity, …. ***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.***

The definition of written power contract includes a number of key concepts: (1) the source must be specifically and unambiguously committed for delivery; (2) the source must be designated at the time the transaction is executed, and; (3) the power must actually be delivered from the designated source, as verified by NERC e-Tags. ARB identified early in the development of the Program that NERC e-Tags alone were not sufficient to conclude that an import was from a specified source. While NERC e-Tags identify the source of the power after-the-fact, they do not establish why that source was used: was the source explicitly contracted for, or was the source selected at the discretion of the out-of-state seller or their upstream source. The former scenario supports the objectives of the Program by maintaining a firm contractual connection to the facility; the latter scenario does not, and in fact is no different than if the Program did not exist at all.

Relying only on after-the-fact NERC e-Tags to establish the emission factor for each import likely would be unworkable and have unwanted consequences throughout the wholesale power market. Hypothetically, an entity that purchases energy for import into California may find that the NERC e-Tag shows a hydro source in some hours, and incurs no liability for ARB compliance instruments, but may find that the e-Tag for another hour shows the source to be a high GHG-emitting coal or natural gas power plant. The supplier's choice of resource would create random outcomes where importers of power that happened to be sourced from a low-GHG resource "win," and importers of power from high-GHG resources "lose." In an environment where NERC e-Tags were the only source of data regarding the power delivered to the state, market participants would be incented to lift offers on anonymous electronic exchanges looking to coincidentally be matched with low-GHG suppliers, and selling back any residual volume that was not from low-GHG suppliers.

For an import to be from a specified source under ARB's existing framework, a degree of intentionality is required. Requiring a written power contract for a specified source provides the evidence of that intentionality. This requirement is combined with NERC e-Tag data to verify direct delivery of electricity from the source previously designated in the written power contract. Thus ARB's two conceptual requirements for specified power are (1) an advanced commitment to deliver power from a specified source (written power contract), and (2) actual delivery from that specified source to California (NERC e-Tags). Powerex supports ARB maintaining these dual requirements.

Advance Commitment Properly Distinguishes Specified and Unspecified Sales. Underlying some of the comments on the proposed MRR amendments that have been submitted to date is the apparent belief that there is no meaningful difference between an ACS selling specified as opposed to unspecified power. This is incorrect, as not all sales by an ACS are contingent upon delivery from the ACS system. For example, Powerex (which is an ACS) draws on the ACS system of its utility parent, BC Hydro, for some of its sales, while drawing on its non-ACS portfolio of specified and unspecified purchases for others. When Powerex makes a sale of unspecified power, it retains the flexibility to use whichever energy resources can satisfy its sale commitments at least cost. It is both possible and common for a multi-hour or multi-day sale to be delivered from its ACS system in some periods, but from its non-ACS resources in others. Conversely, when Powerex makes a sale of *specified ACS system* power, it surrenders that flexibility, and knowingly commits to supplying the energy only from the generating resources that make up its ACS system.

The designation of the ACS system should be no different than the designation of an individual generating unit or facility as specified. An owner of an individual unit may enter into a contract contingent upon delivery from that unit (i.e., specified), or the owner may retain the flexibility to source the power in any manner the owner sees fit (i.e., unspecified). Commenters have not claimed that it is improper for an individual facility owner to contract for both specified and unspecified power, and have not explained why an ACS should be treated any differently.

Powerex agrees that once parties have entered into a contract that clearly identifies the designated source (whether an individual unit or an ACS system) and the contract is contingent upon delivery from that source, the written power contract requirement for a specified transaction will have been satisfied. No additional "stamp" is necessary, and the lack of a "stamp" does not "unspecify" the contract.

Certain Commenters Would Dismantle the Requirement for a Written Contract Contingent Upon Delivery of Power from a Particular Source, But Only for ACS Bilateral Sales. None of the comments on ARB's proposed MRR amendments submitted to date directly challenge or seek to change the two core requirements for specified power – a written power contract contingent upon delivery from a specified source designated at the time the transaction is executed, and performance demonstrated by NERC e-Tag data. However, certain of the comments indirectly challenge the need for a written power contract. Notably, Morgan Stanley Capital Group ("MSCG") proposes that ARB dispense with requiring a written power contract in the very narrow circumstance in which the seller is an ACS engaged in a bilateral sale. In this circumstance only, MSCG proposes that NERC e-Tags showing that the energy was generated in the ACS system would be sufficient to permit the import to be treated as specified, even if the sale was not contingent upon delivery from the ACS system. This singling out of bilateral ACS sales for this proposal is discussed further below. At a fundamental level, however, the MSCG proposal should be recognized as advocating something ARB has previously rejected: treating an import as being from a specified source even when there is no contract requiring that power be delivered from that source.

MSCG's proposal to rely on NERC e-Tags applies only to a subset of commercial arrangements and types of market participants. This treatment would not be applied to all sales by an ACS; only bilateral sales are affected. Moreover, bilateral sales by non-ACS entities would continue to require a written power contract contingent upon delivery from a designated source. The inconsistency between MSCG's proposal for bilateral ACS sales and the requirements that would continue to apply to other types of transactions is depicted below.

	Bilateral Transaction		**Exchange or Anonymous Broker**
	Contingent upon delivery of power from particular source	**Not contingent** upon delivery from particular source	
Specified Facilities	**Specified** *(Actual delivery verified via NERC e-Tag)*	**Unspecified**	**Unspecified**
Asset-Controlling Supplier	**Specified** *(Actual delivery verified via NERC e-Tag)*	**Unspecified**	**Unspecified**
		MSCG Proposed Exception: **Specified** *if NERC e-Tag shows source as ACS Balancing Authority*	

The red-bordered area indicates the special rule MSCG proposes to apply only to bilateral sales by an ACS. The proposal would create an artificial distinction between transactions by ACS and non-ACS entities, while simultaneously discarding the legitimate distinction between sales that are contingent upon delivery of power from a particular source and sales that are not.

The proposal stops short of advocating a complete shift to a "tag only" criterion for ACS purchases. However, MSCG goes so far as to recommend that an ACS simply conduct all its unspecified sales through exchanges such as ICE or through anonymous brokers. In other words, an ACS could continue to sell unspecified power that it delivers from its ACS system, just as other non-ACS suppliers could, but it would have to jump through additional hoops to do so. Such an approach will add transactional friction by forcing ACSs onto exchanges to sell unspecified power and discriminate against ACS suppliers relative to non-ACS suppliers. Moreover, entities considering registering as an ACS, or existing ACS entities considering renewing their status, would see the benefits of this designation eroded by the imposition of restrictions on the commercial transactions they could pursue.

MSCG's argument may rely on the existing definition of "Specified Source" indicating that the ACS entity is itself the specified source. However, there appears to be misalignment between that definition and the related MRR definitions of "written power contract", "direct delivery" and the proposed regulation relating to "Tagging ACS Power."

In Section 2 below, Powerex proposes changes to reconcile the definitions of these critical terms.

For the reasons discussed above, Powerex supports ARB's existing requirement that specified power include a written power contract contingent upon delivery of power from a particular source designated at the time the transaction is executed. MSCG's proposal is contrary to that framework, and also raises concerns about discriminatory treatment toward ACS entities and creating incentives to needlessly distort the commercial behavior of market participants.

<u>Clear ARB Guidance for 2013 is Needed</u>. In 2013, both ACSs and non-ACSs sold unspecified and specified power. Powerex believes that it was widely understood in the marketplace in 2013 which transactions were for specified power versus unspecified power as represented in the respective written power contracts. If ARB's requirement for the clear and contingent designation of an ACS's system for specified ACS power is no longer necessary for transactions already executed in 2013, several issues arise that will need to be addressed.

First, participants will require guidance from ARB regarding which unspecified agreements they entered into, now qualify as specified. If this determination is left to the discretion of participants, the inevitable result will be that some entities will deem a particular agreement as specified while others will deem the very same agreement as unspecified. Not only will this make any subsequent audit process challenging, it will reward those with a more aggressive interpretation of which 2013 agreements qualify as specified, while punishing those that take a more conservative approach. Specific guidance on how to treat specified claims in accordance with MRR § 95111(a)(5)(B), which requires importers to "[r]eport delivered electricity as specified and not as unspecified" even if the import is not associated with a written power contract, should be reconciled with Cap-and-Trade Regulation ("CTR") § 95852(b)(3)(B), which requires importers to have a written power contract.

Second, the aggregate carbon allowances associated with imports into the state likely will fall, reducing demand in the GHG emission allowance market. To prevent any disruption to that market it will be important for ARB to clearly communicate the appropriate treatment of 2013 agreements. Third, those that paid a higher price for specified ACS power backed by a clear written power contract contingent on delivery from the ACS system will feel they were disadvantaged in the wholesale electricity markets relative to those that did not. ARB's communication will be important to restore confidence in the industry that dollars spent to clearly comply with the rules of the program as they were understood at the time were not wasted.

<u>The Rules Governing Specified Power Do Not Determine the Price of Power in California</u>. The price of power in California is determined by many market forces. There is nothing either requiring or enabling an importer to unilaterally increase the price it receives in California whenever it pays a premium to acquire specified power, or to decrease the sale price whenever it avoids that premium by acquiring unspecified or relatively high-GHG power. While the impact on market prices is speculative, the

impact to the importer, the owner of the clean resource, and California GHG emission allowance revenues are not. Allowing an importer to claim a sale of unspecified power as a specified power import transfers the value of the clean resource from the owner to the importer and likely reduces allowance revenue to the state of California.

For the foregoing reasons, Powerex urges ARB to maintain the previously established principles governing claims of specified sources (i.e., a written power contract contingent upon delivery from a specific source designated at the time the transaction is executed, with actual performance verified via NERC e-Tags). These principles should continue to be applied on a non-discriminatory basis to all specified sources, including ACS systems. [OP 26.01 — Powerex]

Response: ARB staff appreciates the support from Powerex on the proposed amendments to section 95111(a)(5)(B). Powerex offers comments on numerous topics under the umbrella of its 95111(a)(5)(B) comments. ARB staff generally agrees with Powerex's review of the role of the written power contract requirement in our existing framework. We agree with the Powerex comments on ACS sales of unspecified power, which Powerex describes under the heading, Advance Commitment Properly Distinguishes Specified and Unspecified Sales. Specifically, once parties have entered into a contract that clearly identifies the designated source (whether an individual unit or an ACS system) and the contract is contingent upon delivery from that source, the written power contract requirement for a specified transaction will have been satisfied. No additional "stamp" is necessary, and the lack of a "stamp" does not "unspecify" the contract. ARB staff agrees with Powerex's comments on the MSCG proposal; a specified source contract will be required in order to claim ACS power. ARB staff has included regulatory language about which unspecified agreements for ACS power will qualify as specified, as described in section 95103(h)(8). Similarly, ARB has prescribed the appropriate treatment of 2013 agreements in that section. ARB staff appreciates the comment from Powerex on the subject of clear written communication of guidance, and ARB staff will work with stakeholders on this issue, as needed.

B-2k. Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)

Comment: Powerex, in oral comments before the Board, reiterated support for points made in its written comments, including requirements for written power contracts for all specified source claims, associated tagging, and that ARB adopt the seller control approach as expressed in the ISOR staff report. Powerex also stated that the proposal would benefit from another round of comment.
[T 02.01 — Powerex]

Response: See Responses to comments B-2a and B-2j.

B-2l. <u>Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)</u>

<u>Comment</u>: LADWP. §95111(a)(5)(B) Imported Electricity Supplied by Asset-Controlling Suppliers: ARB should consider the consequences for the statewide GHG emissions inventory and the cap-and-trade program before deciding whether to assign default GHG emissions to low-GHG power generated by Asset Controlling Suppliers.

Asset Controlling Suppliers are entities that operate a system (fleet of generating resources) and sell power from their system rather than from individual generating facilities. Bonneville Power Administration and Powerex (for BC Hydro) are recognized by ARB as Asset Controlling Suppliers (ACS). Since the systems operated by Bonneville Power Administration and Powerex contain a significant amount of hydroelectric generation, power supplied from these systems has a very low GHG emission factor (0.0249 metric tons CO2e/MWh and 0.0293 metric tons CO2e/MWh respectively).

Section §95111(a)(5) of the MRR, which contains the criteria for reporting imported electricity supplied by an ACS, states that electricity supplied by an ACS, where the ACS is identified as the Purchasing/Selling Entity (PSE) at the first point of receipt on the physical path of NERC e-tags, must be reported as specified and not as unspecified. Under the existing criteria, all imported electricity that originated from the ACS's system can be reported as a specified import with the associated low GHG emission factor.

As part of the 2013 amendments to the MRR, ARB is proposing to change the criteria for reporting imported electricity supplied by an ACS. ARB is proposing to delete "Report delivered electricity as specified and not as unspecified" in §95111(a)(5)(B) and replace it with "Report asset-controlling supplier power that was not acquired as specified power, as unspecified power." In effect, this change will limit the amount of ACS power that can be reported as a specified import with the associated low-GHG emission factor to only those transactions where the ACS was specified as the source at the time the transaction was executed.

LADWP encourages ARB to consider the potential consequences this proposed amendment could have for both the statewide GHG emissions inventory and the cap-and-trade program.

- <u>Statewide GHG Emissions Inventory</u>: For the past several years, all imported ACS power has been counted as low GHG in California's statewide GHG emissions inventory. If this proposed amendment is adopted, the default GHG emission factor (0.428 metric tons CO2e/MWh) will be assigned to imported ACS power that doesn't meet the new criteria. Assigning default GHG emissions to power originating from a low GHG source is not accurate, and will artificially inflate GHG emissions for imported electricity in California's statewide GHG emissions inventory. As a result, additional GHG emission reductions will be required from other sources in order to achieve California's goal of reducing statewide GHG emissions to 1990 levels by 2020.

- Cap-and-Trade Program: Reporting default emissions for ACS power will increase the electricity importer's compliance obligation under the cap-and-trade program and consume valuable GHG emission allowances for emissions that don't exist. Tightening the supply of emission allowances available for compliance could increase the cost of compliance for covered entities.

If this proposed amendment is adopted, the methods available to Electric Power Entities to satisfy the new specified source contract requirement should not be limited to just written confirmations. LADWP recommends that an enabling agreement and/or recorded phone conversations between purchasing and selling entities pursuant to a master agreement should also be acceptable forms of documentation. LADWP transacts with Asset Controlling Suppliers almost daily in the day-ahead and real-time energy markets. In consideration of the frequency with which these transactions occur, recognizing recorded phone conversations as specified contracts for ACS energy transactions would facilitate LADWP's ability to optimize its system dispatch while minimizing its cap-and-trade compliance obligation. Transactions documented via recorded phone conversations occur frequently and are considered standard industry practice.

B-2m. Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)

Comment: LADWP understands ARB's concern regarding the verification and warranting of the specified energy along the market path. To address this, market mechanisms exist, including master agreements which have in place provisions requiring the seller to warrant the product being sold. If a seller cannot deliver the specified product, the buyer may impose penalties on the seller.
[B 01.06 — LADWP]

B-2n. Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)

Comment: During oral comments before the Board, LADWP reiterated its concern expressed in written comments, that not all imported ACS power which has been previously counted as low GHG in California's statewide GHG emissions inventory, would not continue to be reported in this manner. [T 05.02 — LADWP]

Response: (this response addresses comments B-2l and B-2-n) ARB staff disagrees with the concerns raised by LADWP. Under the MRR, ARB staff must ensure the accurate reporting of emissions based on the cap-and-trade and mandatory reporting frameworks set forth in the respective regulations. LADWP argues that the proposed language in §95111(a)(5)(B) will limit the amount of ACS power that can be reported as a specified import with the associated low-GHG emission factor to only those transactions where the ACS was specified as the source at the time the transaction was executed. However, under the specified source of electricity definition in section 95102(a), *specified source also means electricity procured from an asset-controlling supplier recognized by the ARB*. And, in order for an electric power entity to claim a specified source, section 95852(b)(3)(B) of the Cap-and-Trade regulation requires that the "*electricity importer must be the facility operator or have right of ownership or a written power contract, as defined in MRR section 95102(a), to the amount of electricity claimed and generated by the facility or unit claimed*" and section 95852(b)(3)(C) requires that the "*electricity must be directly delivered, as defined in MRR section 95102(a), to the California grid*." Among the four options for "directly delivered" electricity as defined in section 95102(a), direct delivery of electricity can be demonstrated to California "*via a continuous physical transmission path from interconnection of the facility in the balancing authority in which the facility is located to a sink located in the state of California,*" as shown on one e-tag in the physical path table. As such, under the existing regulatory requirements, in order to claim ACS power, an EPE must acquire that power under the requirements necessary to claim specified source power. Otherwise, the power must be claimed as unspecified.

ARB disagrees with the LADWP assertion that "assigning default GHG emissions to power originating from a low GHG source is not accurate, and will artificially inflate GHG emissions for imported electricity in California's statewide GHG emissions inventory." ARB's reporting program contains a contract based framework, not one that is entirely e-tag based. LADWP is essentially arguing for an e-tag based approach but only for ACS power. This is inconsistent with our framework approach where ACS and specified source power are aligned as specified sources. ARB also disagrees with LADWP's second assertion that reporting default emissions for ACS power will increase the electricity importer's compliance obligation, for reasons already stated. LADWP's last comment on seller warranty is addressed in Response to comment B-1a-h. For all of these reasons, ARB staff is not proposing any further changes to these regulatory provisions.

B-3. <u>Transmission Loss Factor for Reporting Asset Controlling Supplier Power, Section 95111(a)(5)(D) and 95111(b)(3).</u>

<u>Comment</u>: BPA offers no comment regarding the actual proposed change in the regulation language. However, BPA suggests that CARB remove two sentences from the ISOR that describe the rationale for this change. In the ISOR CARB states that the purpose of this proposed update is "to establish the requirement that all power claimed as asset-controlling supplier power must utilize the transmission loss factor of 1.02."

While the Bonneville Power Authority [sic] (BPA) service territory does extend into California, it does so only at the distribution level and power is only provided at that level to one entity, Surprise Valley Electric, an electric cooperative. No other electric power entities take delivery of BPA power from that portion of its service territory that extends into California.

These sentences are not necessary to explain CARB's proposed change. The sentences also contain incorrectly-used terms (BPA does not supply power at the "distribution level") and cause confusion by seemingly suggesting that BPA's supply of power to Surprise Valley may be an exception to the new 1.02 loss factor requirement. BPA does not believe that such an exception is needed. BPA intends to use a transmission loss factor of 1.02 when reporting its sales to Surprise Valley Electric Cooperative. To avoid the confusion and unnecessary questions raised by these two sentences, BPA requests that CARB delete them from the Final Statement of Reasons. This deletion would not alter the meaning of the rest of the paragraph.
[OP 18.06 – BPA]

Response: ARB staff has withdrawn the proposed changes regarding the transmission loss factor for asset controlling supplier power in section 95111(a)(5)(D) and 95111(b)(3) as part of the 15-day changes. Upon further review, it is clear that a more straightforward modification to the regulation would more accurately account for transmission loss associated with specified source claims. In the future, ARB staff intends to revisit the characterization of the transmission loss factor values. Regarding BPA's suggestion that ARB delete two sentences from the ISOR, ARB staff notes that the ISOR is a fixed document which was noticed to the public on September 4, 2013; as such, no changes may be made to the ISOR itself. However, given that ARB staff has reverted to the original regulatory language in the 15-day changes, ARB staff notes that the language at issue in the ISOR no longer applies.

B-4a. Tagging Asset Controlling Supplier Power, Section 95111(a)(5)(E)

Comment: MSCG offers several clarifying edits in support of the tagging proposal for ACS power, as shown here:

(E) *Tagging ACS Power.* To claim power from an asset-controlling supplier, the asset-controlling supplier's Balancing Authority Area must be identified as the source on the physical path of the NERC e-Tag and the asset-controlling supplier as the PSE at the first point of receipt, or in the case of asset controlling suppliers that are exclusive marketers, the associated generation owner's Balancing Authority Area must be shown as the source on the NERC e-Tag and the asset controlling supplier as the PSE immediately following the associated generation owner.

[OP 01.05 – MSCG]

B-4b. Tagging Asset Controlling Supplier Power, Section 95111(a)(5)(E)

Comment: BPA acknowledges that ARB has proposed changes to this section. BPA's comments focus on path outs as opposed to tagging, and are addressed in the following item on path outs. [OP 18.04 – BPA]

B-4c. Tagging Asset Controlling Supplier Power, Section 95111(a)(5)(E)

Comment: Powerex. The power contract and direct delivery definitions refer to the energy resources of an ACS, as opposed to the ACS entity itself. ARB's proposal to add a new provision, MRR § 95111(a)(5)(E) entitled “Tagging ACS Power,” appropriately and clearly refers to an ACS as a purchasing selling entity (“PSE”), and not as a defined group of energy resources:

Tagging ACS Power. To claim power from an asset-controlling supplier, the ***asset-controlling supplier must be identified on the physical path of the NERC e-Tag as the PSE*** at the first point of receipt, or in the case of asset controlling suppliers that are exclusive marketers, as the PSE immediately following the associated generation owner, with the exception of path outs. … [**emphasis added by Powerex to language proposed by ARB**]

Therefore, to maintain alignment with the dual requirement of a written power contract and direct delivery, and consistency with the proposed new MRR § 95111(a)(5)(E), Powerex respectfully submits that its recommended changes to the specified source and asset controlling supplier definitions to clarify reference to the system of an ACS entity. [OP 26.07 - PX]

Response: (This response addresses comments B-4a-c) ARB staff appreciates MSCG's support of the ACS tagging proposal. In the 2012 MRR FSOR, we did allow for the possibility that “some ACS resources may to a small degree span more than one balancing area.” Thus, we decline to make the proposed edits at this time as they could prove unnecessarily restrictive for a reasonably situated future ACS entity. ARB staff thanks Powerex for support of the proposed language. Regarding Powerex’s specific changes to the definitions of “specified source” and “asset-controlling supplier,” please see response to comments A-20 and A-10.

B-5a. Path Outs, Section 95111(a)(5)(E)

Comment: Morgan Stanley opposes the proposed path out language, where excess power procured by an asset controlling supplier with a federal mandate, would be exempt from MRR tagging requirements. Morgan Stanley states that allowing exceptions for “path outs,” in combination with the asset controlling supplier seller control proposal, would facilitate resource shuffling which is inconsistent with the calculation methodology of the ACS emission factor. [OP 01.02 – MSCG]

B-5b. Path Outs, Section 95111(a)(5)(E)

Comment: PacifiCorp states that proposed language in section 95111(a)(5) clearly provides for an ACS power claim to be identified through the first line of the physical path of the e-Tag "specifying the generation control area" of the ACS, with the exception of "path-outs" for the Bonneville Power Administration (BPA) as an ACS. An ACS entity should not be able to distinguish if the generation is system or surplus but rather if it is an ACS all the generation should be part of the calculation to determine its emission factor. In addition, an ACS entity should not be permitted to say that the same ACS control area source can have different factors for different buyers that may be directly contracting with that ACS, depending, for example, if the ACS entity is selling from its

ACS portfolio or a non-ACS "portfolio" that is registered under the same legal entity or marketing agency. Further, the rules should not allow for an ACS entity to import specified or unspecified power into its balancing authority "sink the generation" and then by an effective de-designation or non-designation, regenerate ACS energy and sell it at a different emission factor. [OP 15.03 – PC]

B-5c. Path Outs, Section 95111(a)(5)(E)

Comment: BPA supports the general purpose of the new path out provisions, but recommends certain edits. First, the references to path outs. BPA understands and appreciates CARB's effort to acknowledge that, under BPA's governing federal laws, any purchase that BPA makes is a part of BPA's "federal system." That is, federal law only allows BPA to make purchases for the purpose of serving load, however, there are times when demand or system conditions change and BPA no longer needs energy originally purchased to serve load. In such cases BPA may schedule power originally intended to meet federal system load with subsequent sales, resulting in a "path-out" of balancing purchases and sales. This practice is not unique to BPA and has the added benefit of making efficient use of transmission. BPA appreciates CARB acknowledging that BPA's "federal system" consists of federal generation and purchases that might be "pathed-out" with "federal system" sales.

BPA's concern is that the proposed language regarding path outs implies that path outs are a BPA-only practice. They are not; many in the industry "path-out" energy purchases and sales. Therefore, in order to more accurately describe the acceptable tagging practices of BPA ACS power, BPA recommends eliminating the references to the term "path out" (which is a general industry term) and rewriting the language as follows:

(E) *Tagging ACS Power*. To claim power from an asset-controlling supplier, the asset-controlling supplier must be identified on the physical path of the NERC e-Tag as the PSE at the first point of receipt, or in the case of asset controlling suppliers that are exclusive marketers, as the PSE immediately following the associated generation owner, with the exception of a U.S. federal ACS whose ACS system definition includes energy purchases~~path outs. Path outs are excess power,~~ originally procured as part of a U.S. federal mandate to serve the operational or reliability needs of a U.S. federal system. Federal energy purchases that ~~but which~~ are no longer required to meet a U.S. federal mandate due to changes in demand or system conditions can become surplus and can be resold as ACS power in the market with the ACS listed on either the physical or market path of the NERC e-Tag.

These changes better describe CARB's purpose, which is to allow BPA to adhere to its federal system definition that includes generation and system balancing purchases, which sometimes may result in path-outs when the federal system needs change.

Second, the last line of BPA's suggested edits includes the words "or market path." This addition is necessary because, as BPA has explained and demonstrated to CARB staff through examples, when BPA paths-out surplus purchases and sales at the same point of delivery (POD), BPA does not use transmission and is thereby only listed on the market path of the NERC e-tag. It is only when an entity uses transmission to schedule a path-out between two different PODs that the entity is listed on the physical path and the market path of the NERC e-Tag. CARB staff has indicated that it is permissible to include both of these types of path-outs for purposes of BPA's ACS system. Accordingly, the words "or market path" are necessary to encompass path-outs that do not require transmission and do not result in BPA being listed in the physical path. [OP 18.05 – BPA]

Response: (This response addresses B-5, a-c) After further evaluating the potential implementation of the proposed path-out language, ARB staff agrees with the concerns expressed by Morgan Stanley and PacifiCorp. The proposed language was specific to BPA as it was designed to reflect their operational practices. The proposed language would allow BPA to use any source inside or outside its balancing authority area and sink that power just about anywhere, using the BPA ACS rate. This possibility raises a number of concerns. First, the path out provision could potentially blur the line between ACS and non-ACS power. For example, an e-tag with a source other than BPA Power could have received the BPA ACS emission rate, in the event that BPA was in the physical path, or if BPA was in the market path as proposed by BPA in comments. Second, the path out provision would complicate the verification process. Under the path out proposal (and BPA modification), almost any e-tag with BPA in the physical path or in the market path would have potentially been eligible as an ACS power claim, assuming other requirements were met. This would result in decreased transparency for buyers, especially if combined with the seller control proposal. A buyer that transacts directly with BPA could end up with a BPA power product that is considered unspecified, or the buyer could end up with e-tags to a coal plant that are allegedly eligible for the BPA ACS rate. The path out proposal does not align with a clear and stable mandatory reporting framework for GHG accounting. For the reasons stated, and in response to stakeholder comments, ARB staff has proposed 15-day changes which remove the originally proposed path-out language. These 15-day changes also mean that ARB declines to make the changes recommended by BPA for the reasons stated above.

B-6a. System Power, Section 95111(a)(12).

[NOTE: ARB staff will address the proposed system power issue relative to all commenters in response B-6a, and then address comments individually, as appropriate, in separate responses.]

Comment: Morgan Stanley stated the proposed system power amendments appear to introduce something different from ACS power. As we understand it, this situation would arise under ARB's own initiative, rather than when a "system" applied for the designation. The intent appears to be to better align actual emissions with reported emissions, when a "system" has an emission rate above the default emission rate, and would thereby have no reason to sell any power as "specified". MSCG has no objections to the concept. However, there is one significant concern with the practical implementation. A party may have entered into a contract, in good faith, under the existing rules. In that situation, the economic balance of the contract would most likely have been based on the assumption that the attributable emissions of the transaction would be the "default" rate. For ARB to, after the fact, declare a transaction from a certain "system" to be assigned an emission factor higher than the default rate would be inequitable. Therefore, the new system power regulations need to include a "grandfathering" clause for contracts in place prior to the posting of the relevant "system power" emission factor on the ARB web site. Contracts in place would not be affected, and the new system power rate should only apply to any contract entered into after the effective date of the new rate. To do otherwise will recreate in a different guise the "Legacy Contract" issue that is addressed in the companion Proposed Amendments to the Cap and Trade Regulation. [OP 01.06 – MSCG]

Response: In 15-day changes, ARB staff has withdrawn the system power proposal in its entirety. Rather than make a change now, it was clear from comments that ARB will require additional stakeholder engagement to determine if there is indeed a need to refine how the emissions associated with some imported electricity is calculated.

. With regard to the concern that contracts in place should not be negatively affected, ARB staff agrees with the commenter and will work with stakeholders on this issue in the event the proposal is ever slated for future consideration.

B-6b. System Power, Section 95111(a)(12).

Comment: WPTF stated that the proposed amendments retain provisions proposed in the informal discussion draft that would result in assignment of a 'system-specific' emission rate calculated by CARB for imports of system resources when the blended emission rate of those resources is higher than the default emission factor. It is not clear, however, whether the high emission factor will be assigned only to direct imports by the system owner and imports procured pursuant to a specified power contract with the system owner or whether CARB would assign the emission factor to any tags originating from such systems. WPTF understands from conversations with staff that CARB is likely to rescind these proposed additions. If CARB retains these provisions, then it must ensure that they conform to the rest of the regulation. Specifically, the high system emission factor should be applied only when the system owner imports directly, or an intermediary imports pursuant to a specified contract. Identification of the system on a tag alone should not result in assignment of the system emission rate.
[OP 02.08 – WPTF]

Response: In 15-day changes, ARB staff has withdrawn the system power proposal in its entirety. ARB staff had intended that the system emission factor would have been assigned only to direct imports by the system owner and imports procured pursuant to a specified power contract with the system owner or specified source reseller, not simply based on tags originating such systems. Additionally, see response to comment B-6a.

B-6c. System Power, Section 95111(a)(12).

Comment: PacifiCorp continues to have significant concerns regarding what is increasingly becoming ARB's attempt to regulate wholesale power markets in the West and ARB's attendant lack of authority over those wholesale power markets, inside and out of California. Allowing or requiring the use of system emission factors for some subset of (or all) entities in the West is discriminatory and has the effect of setting a different price for the energy from one specific wholesale market participant versus another. It also creates a situation where each wholesale product must be tracked from source to sink. Because wholesale market products are generally from unspecified resources and not differentiated by system, the application of system emission factors has the potential to cause a significant shift in the entire market. It is therefore highly likely that ARB's shift toward system-specific pricing will result in unintended consequences.

PacifiCorp understands ARB's motivation and shift toward system emission factors. Indeed, this approach may be consistent with the intent of the MRR and the Cap-and-Trade Program, which is specifically designed to ensure that a carbon price is incorporated into commodity pricing. However, as will be described in detail below, ARB does not have the jurisdiction or authority to regulate imported power or electricity importers, or to modify the bilateral wholesale market to accommodate system-specific pricing.

Further, it is problematic that ARB does not currently have an effective enforcement mechanism for ensuring that system specific or resource specific emission factors are consistently applied or claimed. This again would require greater jurisdiction over the wholesale energy markets. ARB does not have the authority or jurisdiction to impose its program outside of the state of California or on the wholesale market.

The issue of "leakage" that ARB is attempting to address by calculating system emission factors is simply not one that ARB currently has the authority to resolve. ARB's regulations should recognize ARB's limited jurisdiction and not seek to regulate energy imports or importers. PacifiCorp recommends that the greenhouse gas ("GHG") obligation and cost associated with energy imports or importers be the obligation of the source (load) utilizing the energy. ARB has the authority to regulate costs and obligations associated with GHG in the state of California. The GHG obligation associated with energy that is imported into California should fall to the load in California and not be an obligation of the out of state energy importer. This could be achieved if ARB required all system power (include that from ACS entities) be deemed unspecified and apply the default emission factor, regardless of the entity, into the economics of the entity purchasing the energy to serve load. Parties serving load in California would factor in the cost of the GHG associated with energy from out of state prior to purchasing the imported energy. Further detail regarding the legal basis for why ARB does not have authority over wholesale power markets or imported power is provided below.

PacifiCorp Comments on Jurisdiction: The MRR and Cap-and-Trade Program intrude on an area of regulation subject to the exclusive jurisdiction of FERC. The Federal Power Act ("FPA") vests in FERC exclusive jurisdiction over, among other things, the rates, terms, and conditions for the sale of electric energy in instate commerce. *See, e.g.*, 16 U.S.C. §§ 824(a), 824d (2006); *New York v. FERC*, 535 U.S. 1 (2002). Indeed, FERC recently itself held that although it lacks jurisdiction over sales of renewable energy certificates (RECs) standing alone, it has jurisdiction over RECs and allowances when bundled with energy otherwise subject to FERC's jurisdiction *See, e.g.*, *WSPP Inc.*, 139 FERC ¶ 61,061 (2012) (finding that (1) an unbundled REC transaction that is independent of a wholesale electric energy transaction does not fall within FERC's jurisdiction under sections 201, 205 and 206 of the FPA, but that (2) a bundled REC transaction, where a wholesale energy sale and a REC sale take place as part of the same transaction, does fall within FERC jurisdiction under FPA sections 205 and 206, as to both the wholesale energy portion of the transaction and the RECs portion of the transaction, and regardless of whether the contract price is allocated separately between the energy and RECs). Further, FERC has also held that, if a wholesale sale of electric energy by a public utility requires the use of an emissions allowance, that sale, and the cost of allowances in connection with it, is subject to review under FPA section 205. *Id*. at P 23 (citing *Edison Elec. Inst.*, 69 FERC ¶ 61,344 at 62,289 (1994) and explaining that such a sale or transfer of an emissions allowance may "affect" the rates a utility charges "for or in connection with" jurisdictional service, which triggers FERC jurisdiction under the language of Section 205 of the FPA). FERC also found in the *Edison Electric* order that, if the sale or transfer occurs independent of a sale of electric energy for resale in interstate commerce, it is outside of FERC review under FPA Section 205, unless a public utility seeks to flow through the costs in its wholesale rates. *Id*.

The adoption and use of system emission factors for entities outside California interferes with FERC's regulation of interstate energy transactions because it effectively imposes a different mechanism for pricing wholesale transactions. Legal precedent is clear that state laws cannot interfere with or frustrate federal laws. *See, e.g.*, *Printz v. U.S.*, 521 U.S. 898, 913 (1997) (noting that all state officials have a duty to enact, enforce, and interpret state law in such fashion so as not to obstruct the operation of federal law, and that all state actions constituting such obstruction, even legislative acts, are *ipso facto* invalid); *Felder v. Casey*, 487 U.S. 131, 138 (1988) ("'any state law, however clearly within a State's acknowledged power, which interferes with or is contrary to federal law, must yield.'") (quoting *Free v. Bland*, 369 U.S. 663, 666 (1962)); *see also De Canas v. Bica*, 424 U.S. 351, 357 (1976) ("Of course, even state regulation designed to protect vital state interests must give way to paramount federal legislation.").

FERC has exclusive jurisdiction over wholesale markets. In exercising that jurisdiction, FERC would not be enforcing California's GHG rules or laws. Furthermore, short of an act of congress, FERC's jurisdiction over wholesale power markets is not a substitute for ARB's jurisdiction. While ARB does not have the authority to regulate and enforce wholesale market activities, FERC similarly does not have the authority to regulate or enforce California law. Therefore, unless new laws are passed by the United States congress, neither ARB nor FERC have the ability to regulate and enforce a multi-state cap-and-trade program. [OP 15.01 – PC]

Response: ARB staff appreciates the comments from PacifiCorp, but believes Pacificorps misstates the regulatory purpose and authority of ARB with regards to greenhouse gas emissions and imported power. There are jurisdictional limits to ARB's regulatory authority, but ARB staff does have the ability to regulate imported power and electricity importers as set forth in the GHG reporting regulation and the Cap-and-Trade Regulation. ARB staff note that it is not attempting to infringe on an area where FERC holds exclusive jurisdiction. To the extent that ARB can calculate an emission factor for an out of state generation resource from which power is imported into California, ARB could similarly calculate a system emission factor for an out of state system from which power is imported into California. ARB considers this a reasonable and lawful feature of the proposal. Notwithstanding the above, this discussion is moot given that ARB has withdrawn the system emission factor proposal, as described in response to comment B-6a.

B-6d. System Power, Section 95111(a)(12).

Comment: APS comments that CARB is proposing that in the event system power imports are above the default emission factor for unspecified electricity imports, if the electricity is not tagged as originating from unique specified sources of generation but instead tagged as system power, it cannot be claimed as coming from an unspecified source. Conversations with CARB staff have indicated the potential for retroactive applicability of this rule.

This proposed change will create a significant level of uncertainty for wholesale market participants transacting in the California electricity market. Such transactions often include packaged electricity that originates from multiple sources having different emission factors. Tracing each electron to its source under such circumstances will not be feasible and will leave participants wondering how to comply. Such a result can be expected to have the undesired effect of reducing entry into the California import market, thereby decreasing liquidity and potentially creating supply problems therein.

In discussing this issue with CARB staff, APS was informed that if APS does not register as an asset-controlling supplier, CARB will calculate and assign a system rate to APS. However, as we previously explained to CARB (see letter to CARB declaring APS's reporting status under the MRR dated November 19, 2012), the electricity APS sells into the CAISO is from a combination of purchased power and from facilities owned or operated by APS. The MRR in no way prescribes that an out-of-state entity, like APS, selling fungible, excess power serving the bulk power system must register itself to be an asset-controlling supplier. Were such registration required, it would be unlawful for lack of fundamental fairness in that it would require out-of-state generators not purposely engaging in the sale of electricity for delivery to the California grid to register as asset-controlling suppliers notwithstanding the fact that the electricity they send to the CAISO is generated from sources outside of California and, without the generators' knowledge or control, purchased by entities in California for consumption within the state. Such disparate treatment would unfairly penalize out-of-state sellers by making it more expensive for them to sell their electricity to the CAISO.

In any event, to the extent CARB intends for this rule change to apply to transactions consummated prior to its final promulgation, such a result would constitute an impermissible retroactive application. Government agencies may not promulgate a new rule that has a retroactive effect on a regulated entity's prior actions. In other words, CARB may not promulgate and use a new regulation to establish a new requirement that would change the legal consequences of an electricity importer's past conduct. Such an impermissible retroactive application of the law would place an undue burden on the entity. Regulated entities make important decisions and adjust their behavior based on the law in effect at the time, and they should not be penalized by later-enacted regulatory changes having retroactive applicability. California courts recognize the well-established presumption against retroactive application of laws. This presumption is deeply rooted in American jurisprudence, and CARB's actions are constrained by the general requirement that all laws and regulations shall have only future effect unless the text of the authorizing statute explicitly states otherwise.

We understand CARB is considering withdrawing the proposed language that is the subject of this comment. To the extent this is the case, we support such action for the reasons discussed above. [OP 20.01 – APS]

Response: ARB staff disagrees that the proposal would have created a significant amount of uncertainty in wholesale markets. ARB staff had proposed a contract and e-tag based approach, not one entirely based on e-tags. And, even under an e-tag based approach, there would be no requirement to 'trace electrons,' given the current power scheduling practices using e-tags which does not track the actual flow of electrons but instead tracks scheduled power. Accordingly, buyers and sellers would have been able to control their exposure to system power emission factors through the use of specified source contracts and e-tags. Notwithstanding this explanation, ARB staff notes that this issue is now moot given that ARB staff has withdrawn the system emission factor proposal in the 15-day changes, as described in response to comment B-6a. ARB staff notes that the remainder of APS' comment letter OP20 concerned suggested changes to the Cap-and-Trade Regulation. As that is a separate rulemaking, ARB staff is not responding to that portion of the comment letter in this FSOR.

B-6e. System Power, Section 95111(a)(12).

Comment: J. Aron/Goldman Sachs states that the proposal, for specified source imports from power systems with blended emissions rates higher than the default emissions rate, would be subject to system-specific emissions factors and will no longer be eligible for the default emissions rate. If this concept only applies to specified power sales, and if the qualification for specified power is being modified to require the conveyance of an attribute, does this concept still make sense? For example, in the absence of language on seller warrants, would specified power sales from such systems become unspecified? If so, it is unclear how the system-specific emission rates would ever be used. Another issue would be to not apply this concept to existing contracts that may have been negotiated under the assumption of a default emissions factor. This can be addressed by applying any changes prospectively. [OP 11.03 – JA/GS]

Response: See Response to comments B-6a and B-6d. See Response to comment B-1a on seller warranty issues. See Response to comment B-6a on existing contracts.

B-6f. System Power, Section 95111(a)(12).

Comment: SCPPA states that the proposed changes to the regulation include several changes providing that if an entity imports "system power" which has an emissions factor higher than the default emissions factor, the importer must use the emissions factor the ARB publishes for that system, rather than the default emissions factor. An ARB staff member informed SCPPA on September 24, 2013, that staff plans to recommend the removal of these new sections. SCPPA supports the removal of the system power provisions. [OP 12.08 – SCPPA]

Response: See Response to comment B-6a.

B-6g. System Power, Section 95111(a)(12).

Comment: ARB staff has indicated to SCE that they intend to remove the Proposed Amendments related to system power. SCE supports removing these amendments and encourages the ARB to release 15-day changes reflecting ARB staff's proposed removal of the system power language. As SCE stated in its comments on the ARB's Discussion Draft of Potential Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, the addition of system power emission factors would diverge from the ARB's existing methodology of accounting for emissions of imported power through a single unspecified Western Electricity Coordinating Council ("WECC")-wide regional emission factor. It would not be appropriate to increase high-emissions systems' emission factors, and thus increase total reported emissions, without simultaneously decreasing the default emission factor for unspecified electricity to account for the reduced emissions intensity of the rest of the WECC-wide electricity pool. To avoid inflating total reported emissions by assessing power from high-emissions systems at a higher emission factor while leaving the default emission factor (for average- and low-emissions systems) unchanged, SCE supports the ARB staff's intention to remove all references to system power emission factors from the Proposed Amendments to the MRR.

If the ARB decides to move forward with the system power provisions, however, the ARB should make a number of modifications to the MRR and Initial Statement of Reasons ("ISOR") in order to clarify the definition of system power. As the Proposed Amendments currently read, it is possible to interpret system power in two different ways. System power could be understood to mean specified power from a system with an emission factor above the default. Alternatively, system power could be interpreted to mean any power from a system with an emission factor above the default, even if it is purchased as unspecified power. Based on discussions with ARB staff, SCE understands that system power should be read to mean specified power from a system with an emission factor above the default. SCE's proposed edits, as shown below, clarify the MRR and the ISOR to reflect this intent.

SCE suggests that the ARB make three changes to the MRR. First, the ARB should modify the last sentence in the definition of "power contract" or "written power contract" in Section 95102(a)(356) as follows to clarify what the ARB means by a "system" given that there are many "systems" referenced in the regulation:

MRR Section 95102(a)(356): "A power contract for a specified source is a contract that is contingent upon delivery of power from a particular facility, unit, system power supplier's system, or asset-controlling supplier's system that is designated at the time the transaction is executed."

Second, the ARB should modify other definitions in the MRR as follows to better align system power reporting rules with those for asset-controlling supplier power, which is explicitly defined as specified power:

MRR Section 95102(a)(437): "'Specified source of electricity' or 'specified source' means a facility or unit which is permitted to be claimed as the source of electricity delivered…. Specified source**s can include**~~also means~~ electricity procured from an asset-controlling supplier **or system power supplier** recognized by the ARB."

MRR Section 95102(a)(451): "'System power' means wholesale electricity procured from a system power supplier and NERC e-tagged as a representative weighted average power output from all generation resources under the ownership or control of the system power supplier which contribute to the power output mix. For purposes of this article, this definition applies to cases where the carbon intensity of the system power supplier's weighted average power output is greater than the default emission factor set forth in 95111(b)(1). **System power is a type of specified power.**"

Additionally, SCE recommends four modifications to the ISOR to eliminate the inconsistent in-text definitions of system power as power "with a carbon content above the default emission factor." Instead of defining system power in the text of the ISOR, SCE's proposed edits as set forth below leave system power to be defined in the MRR:

ISOR at ES-4: "Add a requirement that purchase~~r~~s of system power **~~with a carbon content above the default emission factor must report using a~~<u>be reported at the</u>** system power emission factor rate as determined by ARB, instead of at the unspecified rate, in order to reflect system power carbon content."

ISOR at 5: "Electric Power Entities: The proposed amendments … for system power language would require purchasers of system power **~~that has a carbon content above the default emission factor~~** to report imported power using a system power emission factor calculated by ARB, instead of the lower default emission factor for unspecified power, in order to accurately reflect the carbon content of the system power."

ISOR at 10: "The amendments … would require purchasers of system power **~~with a carbon content above the default emission factor~~** to report using a system power emission factor rate to be determined by ARB, instead of at the unspecified rate, in order to reflect system power carbon content."

ISOR at 59: "The proposed system power language would require purchasers of system power**~~, where system power is defined as power with a carbon content above the default emission factor,~~** to report imported power at a system power emission factor rate calculated by ARB, instead of at the default emission factor for unspecified power."

Finally, the ARB should provide more clarity on what type of information it would like to see in relation to current and historic e-tagging practices for system power suppliers. Specifically, the ARB should include the type of information it is looking for directly in Section 95111(g)(6), as indicated below:

MRR Section 95111(g)(6): "*Registration Information for System Power Sources*. The following information is required: … (C) Information on current and historical NAESB/NERC e-tagging practices for the system power supplier**<u>, specifically [the type of data/info the ARB is looking for, e.g. sample e-tags from 2011 and 2012]</u>**."

[OP 21.01 – SCE]

<u>Response</u>: ARB staff appreciates SCE's comments. SCE contends that the addition of system power emission factors would render the unspecified rate inaccurate. ARB staff observes that this would likely not be the case, as the unspecified rate is based almost entirely on natural gas generation. And, to the extent that all system power resources, that were represented via system power emission factor, were removed from the unspecified rate calculation methodology, a difference in the resulting unspecified rate may or may not result. Notwithstanding the above explanation, this issue is moot since ARB staff has withdrawn the system emission factor proposal in the 15-day changes, as described in response to comment B-6a.

B-6h. System Power, Section 95111(a)(12).

Comment: SCE stated, in oral comments before the Board, that it supports the 15-day edits that would remove the system power proposal. [T 08.01 – SCE]

Response: See Response to comment B-6a.

B-6i. System Power, Section 95111(a)(12).

Comment: AEPCO supports ARB's proposal to clarify the treatment of system power. As ARB recognized in its July 23rd webinar on draft amendments to the MRR, it is standard practice for some utilities and generators in the West to e-tag power from multiple generation resources within their system as originating at a system hub rather than at the actual generating unit. Unfortunately, the current MRR does not clearly account for this situation. Section 95111(a)(4) of the MRR states that electric power entities (EPEs) "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." The regulations provide that "[e]lectricity 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) . . . ." By implication, all electricity deliveries that do not meet the requirements for "direct delivery" must be claimed as "unspecified."

However, the definition of "direct delivery of electricity" requires that the electricity be "scheduled for delivery from the specified source into a California balancing authority *via a continuous physical transmission path from the interconnection of the facility in the balancing authority in which the facility is located to a sink located in the state of California*." Thus, system power that originates from multiple points in a single balancing authority and is then delivered to a trading hub for resale, would not meet the requirements for "direct delivery" because the e-tag would not show a "continuous physical transmission path from the interconnection of the [source] facility" to the sink. Rather, such power either would be tagged with the source designated as the hub or substation, or as "system power" with the first point of receipt (POR) identified as the trading hub. Consequently, there has been uncertainty among reporting entities as to whether imported system power that is tagged as originating at such hubs should be reported by the importer as "specified" or "unspecified" power.

AEPCO supports ARB's efforts to clarify this ambiguity in the current regulations. ARB believes that the proposed designation of "system power" in proposed new section 95111(b)(5) could allow reporting entities to more accurately report the source and greenhouse gas emission factor of their delivered electricity. AEPCO's understanding is that in the future, ARB would calculate and publish a system-wide emission factor for each system and would require reporting entities importing power from such systems to claim the import as a "specified source" import using the ARB system emission factor. This procedure would be analogous (though not identical) to the procedure ARB already uses for entities that import power from Asset Controlling Suppliers.

Additional Clarification is Needed. AEPCO supports ARB's proposal to clarify its regulations by explicitly recognizing system power as a specified source of power. However, AEPCO believes that further clarification is needed to ensure that entities may correctly report such power. AEPCO requests that ARB clarify the following issues:

1. *What information will ARB use to calculate the system emission factor?*

The draft amendments do not provide much detail as to how ARB will calculate the system emission factor. What publicly available data will ARB use to calculate the factor? Will ARB accept or require other data from reporting entities that may provide a more accurate indication of the greenhouse gas intensity of system power?

One area of particular concern for AEPCO is the potential for disparity in the greenhouse-gas intensity of a system's overall generation portfolio (including purchased power) and the greenhouse-gas intensity of the power the system *delivers* to California. ARB's current proposal does not appear to distinguish between system resources that are used to serve non-California customers and system resources that are used to serve California customers. For example, in AEPCO's case, AEPCO's non-California member-customers may have demand profiles that differ substantially from the electricity demand profile of AEPCO's main California member-customer. Moreover, certain of these member-customers purchase only a portion of their requirements from AEPCO, whereas others purchase all of their requirements from AEPCO. Therefore, AEPCO's system-wide resource mix is likely to differ somewhat from the resource mix associated with the electricity AEPCO actually imports to California.

Consequently, AEPCO suggests that ARB should clarify whether ARB will allow systems to report based on the greenhouse-gas intensity of the system resource mix associated with their actual imports, as opposed to the intensity of the overall system generation profile (much of which is not associated with California imports or electricity consumption and should therefore fall beyond the scope of the cap-and-trade program). AEPCO would welcome an opportunity to discuss this issue further with ARB staff in advance of the issuance of any proposed rule in this area.

2. *What evidence will ARB require for claims of "system power"?*

ARB should clarify the kind of evidence it will require reporting entities to provide in order to demonstrate that a delivery of system power has occurred. <u>In particular, ARB should clarify the specific form, if any, the e-tag must take.</u> The current regulations do not adequately explain this issue, and additional clarification would be helpful to reporting entities in complying with ARB's rules.

3. *How will the proposed "system power" clarification affect the other "specified source" rules?*

ARB should explain how the proposed clarification to allow for reporting of system power will interact with the reporting rules for specified sources. In particular, ARB should explain how ARB would treat deliveries from the same reporting entity that come from both specified individual generation sources and from system sources. In other words, would an entity reporting its deliveries on a "system" basis be permitted to separately report certain deliveries as "specified source" deliveries, assuming that the other requirements for reporting "direct delivery" from a specified source were met (*i.e.*, electricity purchased pursuant to a long-term contract that specifies delivery from a specific source; e-tag with continuous physical transmission path from source facility to sink)?

Consider a concrete example: Suppose First Deliverer A operates its generation resources as a system, and e-tags all deliveries to Customer A from a single system trading/transmission hub. Under the proposed clarification to the ARB reporting rules, First Deliverer A would, in theory, be required to claim the deliveries from the system hub as "system power." Suppose, however, that First Deliverer A signs a Power Purchase Agreement (PPA) with Wind Generator B for procurement of up to 10 MW of wind energy for redelivery to Customer A. Suppose further that First Deliverer A transmits and e-tags the power from this PPA such that the e-tag shows a continuous physical transmission path from the generating source to Customer A. Meanwhile, First Deliverer A continues to supply the remainder of Customer A's demand with system power. Therefore, a portion of the power imported into California comes from a specified source, and the remainder comes from system power. Under these circumstances, would the wind power procured from Wind Generator B under the new PPA, and e-tagged pursuant to the requirements for specified source deliveries, be reported separately from the "system power"? Or would the electricity produced and delivered pursuant to the PPA with Wind Generator B be included in the "system" emission profile calculated by ARB? ARB should clarify how it would address situations such as this in its clarification to the MRR system power rule.

4. *Will ARB be changing the definition of "direct delivery"?*

The current definition of "direct delivery," "continuous physical transmission path," and other aspects of the MRR reflect ARB's previous assumption that all electricity would be e-tagged from a single source, as opposed to a hub or system. Will ARB be amending these definitions as well to reflect this clarification?

5. *Will there be additional registration requirements for systems?*

ARB should clarify whether the addition of a system power option will mean that reporting entities must also register as systems, similar to the way they now register for specified sources.

6. *Will there be additional verification requirements for system power?*

ARB should explain the verification procedures for system power, including whether reporting entities will be required to retain any additional documents or adjust their verification procedures.

7. *Will the "system" clarification apply to electricity deliveries from 2013?*

In the absence of ARB's clarification of the reporting rules, EPEs have been required to continue to deliver electricity to their customers under existing contracts. Many of these deliveries would fall within the concept of system power as proposed in the draft amendments. Should these deliveries, which have already occurred, be reported as specified "system power" deliveries? If so, how should reporting entities calculate their 2013 emission factors for this power? If not, how should such deliveries be reported for emission year 2013?

8. *Why has ARB proposed to authorize system treatment only for imports above the default emission factor?*

The current draft excludes from the "system power" definition any imports of power that are below the default emission factor. What is the rationale for this restriction? If a system's average emissions are below the default emission factor (*e.g.*, due to high renewable, nuclear, or hydroelectric generation), should that system report all imports as unspecified? Such a result would effectively penalize lower-emitting systems by forcing them to report emissions that are higher than their actual emissions. If ARB concludes that systems with emission factors below the default factor must report their emissions as "unspecified," what is ARB's rationale for doing so? [OP 25.01 – AEPCO]

Response: As described in response to comment B-6a, ARB staff has removed the regulatory references to system power. As such, the remainder of this comment no longer applies.

B-6j. System Power, Section 95111(a)(12).

Comment: Per §95111(b)(5), ARB will calculate and publish, on the Mandatory Reporting website prior to each calendar year, the system emission factor for all system power suppliers identified by ARB, for use in determining emissions associated with system power. This section also states that publicly available information, information voluntarily made available, or other information accessible by ARB may be used. It is unclear, however, what specific information or sources of information will be used to calculate these system emission factors and whether system power suppliers will be able to review and comment on their specific factor. Also, it is not clear whether the high emission factor will be assigned only to direct imports by the system owner and imports procured pursuant to a specified power contract with the system owner (or whether ARB would assign the emission factor to any tags originating such systems). PGE requests clarification in the regulation on these items. [OP 27.01 – PGE]

Response: See Response to comment B-6a.

B-6k. System Power, Section 95111(a)(12).

Comment: M-S-R supports CARB staff's intent to strike all reference to system power in the Proposed Amendments. New sections 95111(a)(12) and 95111(b)(5) would impose "system power emission factor rates," that would be determined by CARB. Purchasers of system power with a carbon content above the default emission factor (DEF) would use a new "system power emission factor calculated by ARB," instead of the lower DEF for unspecified power. According to the ISOR, this approach would "more accurately reflect the carbon content of the system power, than the use of the

[DEF] for unspecified electricity imports." M-S-R believes that this proposal includes a number of uncertainties. Several details regarding the implementation of the proposed revision are not clearly addressed in the Proposed Amendments, including how "systems" would be determined and to whom the requirement would apply. As proposed, the reported data would also provide inaccurate information regarding the state's true emissions level, since only systems with emissions determined to be higher than the DEF would be assigned a new emissions factor. Ostensibly, systems with lower emissions would still be subject to the current DEF, which would artificially inflate the overall GHG emissions figures for imported electricity. M-S-R understands that CARB staff intends to recommend to the Board that all of the current references to system power be removed from the Proposed Amendments. M-S-R supports this recommendation and urges the Board not to adopt any new requirements in the MRR regarding system power. M-S-R supports the 15-day changes to remove the system power proposal. [OP 31.01 – MSR]

B-6l. <u>System Power, Section 95111(a)(12).</u>

The comments in B-6k were reiterated by MSR during the public testimony at the board hearing.[T 06.01 — MSR]

<u>Response</u>: For comments B-6k and B-6l, see Response to comment B-6a.

B-6m. <u>System Power, Section 95111(a)(12).</u>

<u>Comment</u>: Shell stated, in oral comments before the Board, that it supports the 15-day edits that would remove the system power proposal. [T 11.02 – Shell]

<u>Response</u>: See Response to comment B-6a.

B-6n. <u>System Power, Section 95111(a)(12).</u>

<u>Comment</u>: LADWP. This proposed new requirement would apply a system specific emission factor to imported electricity supplied from a system (other than an Asset Controlling Supplier's system) that has a GHG emissions factor higher than the default emissions factor, where the system is identified as the source on the NERC e-tag.

On September 24, 2013, an ARB staff member informed the Southern California Public Power Authority that staff plans to recommend removal of these provisions. LADWP supports removal of the system power provisions for the following reasons:

1) Section 95111(a)(12)(B) states: *Report system power that was not acquired as specified power, as unspecified power.*

It is not clear whether this would require electricity importers to (a) report system power that was not acquired as specified power, as unspecified power and apply the default emissions factor, or (b) to report system power as unspecified and apply the higher system specific emissions factor.

2) If the latter case, LADWP believes this would create considerable uncertainty in the wholesale electricity markets. LADWP engages in energy transactions with other balancing authorities daily and bases its trading decisions on the projected incremental cost of energy generation. Among the parameters determining this cost are incremental heat rate and the cost of carbon. Energy traders do not know the origin of the energy when purchasing unspecified electricity. Since the origin of the energy is not known until several hours after the fact when an e-tag is created to facilitate scheduling of the physical energy, traders would have no means of determining the economics of that transaction because the emissions factor would be unknown at the time the transaction was executed. [B 01.07 – LADWP]

Response: ARB staff appreciates the support for the removal of this proposal. As explained in response to comment B-6a, ARB has withdrawn the proposal in 15-day changes. As such, the remainder of this comment no longer applies.

B-6o. System Power, Section 95111(a)(12).

Comment: CARB's Proposal to Calculate A Specific System Rate for System Power Suppliers that are Above the Default Rate Is Appropriate. In order to more accurately reflect the carbon content of power that is imported into California, CARB proposes to "require purchasers of system power that has a carbon content above the default emission factor to report imported power using a system power emission factor calculated by ARB, instead of the lower default emission factor for unspecified power, in order to accurately reflect the carbon content of the system power." IEP supports this proposal.

As noted by CARB, "Some power systems outside California do not tag power at the generation facility or unit level but instead tag power as system power at the system level to reflect the combined output of its generation portfolio." As a result, the existing default emissions factor of 0.428MTCO2e/MWh does not accurately represent the GHG emission profile of power coming into California from a particular system. Accordingly, a system specific emission factor should be calculated for these resources and applied when it exceeds the default rate.

How CARB Calculates The System Rate Is Important. The method by which CARB calculates the "system rate" for an individual power supplier exporting into California is important. CARB's proposal to use the "weighted average power output from all generation resources under the ownership or control of the system power supplier which contributes to the power output mix" will likely be on the conservative side given that it will calculate a rate using the output from *all* generation resources, including renewables and nuclear generation with zero emissions. Given that low or zero emitting generation resources (i.e. renewables and nuclear generation) are likely serving the customers/constituency in the territory in which the power is created due to the co-benefits associated with these types of generation resources, it is likely that

California is indeed receiving power with emission factors in the upper bounds of the rates that were calculated.

CARB Should Ensure that GHG Emissions Reporting is Transparent, Accurate and Does Not Foster Leakage and/or Contract Shuffling. In-state generators subject to CARB's cap-and-trade program are directly reporting emissions, and they have corresponding compliance obligations for the metric tons of CO_2e that they emit. Consequently, using a default emissions factor that does not accurately represent the GHG content of the power that is imported into California creates a clear incentive for a portfolio of relatively high emitting base load resources to categorize its whole portfolio as unspecified in order to obtain a competitive advantage by avoiding its full carbon allowance obligation. This raises questions regarding the fair treatment of in-state vs. out-of-state generation as well as the integrity of the cap and trade program in general.

Accordingly, IEP appreciates CARB's attempt to correct these protocols by calculating a specific emission factor for system power sources whose emissions rate exceeds the default rate. CARB must structure the default emissions factor and system specific emissions factors such that in-state and out-of-state entities face similar standards in terms of GHG compliance obligations; otherwise, in-state generators are at an extreme disadvantage in comparison to their out-of-state competitors.

CARB Should Regularly Update the System Specific Emission Factors for System Power Suppliers. As the attached analysis indicates, power generation fluctuates, new plants open, old plants retire, changes in ownership occur, etc. Accordingly, the emissions factors associated with system power suppliers will need to be updated regularly. Updating these emission factors on a regular basis will give CARB an accurate account of the GHG emissions that are really associated with power that is imported into California. Further, this will allow the CARB to accurately assess the states' progress in achieving the AB 32 goals.

IEP still contends the most accurate way for CARB to account for the GHG emissions associated with imported power is to incentivize the reporting of specified power. IEP has suggested, in the past, that CARB set the default emission factor sufficiently high (i.e. equivalent to the emissions of a coal facility) in order to create an incentive for entities to specify. Under this model, CARB could presume that all resources that remain unspecified are indeed associated with an emissions rate equal to a coal-fired facility.

Remaining Questions Related to Identifying System Power Suppliers. IEP supports CARB's proposal to reconsider the emissions rates of imports delivered into California that are not accurately represented by the default emissions factor. More transparency and accuracy is always better. However, CARB's proposal still leaves a few unanswered questions for stakeholders to consider, including the following:

- How will CARB choose which entities will be considered "system power suppliers"?

- How will CARB decide when to calculate a system specific emission factor? [OP 28.02 — IEP]

Response: As explained in response to comment B-6a, ARB has withdrawn the proposal in 15-day changes. As such, the remainder of this comment no longer applies.

B-6p. System Power, Section 95111(a)(12).

Comment: In oral comments before the Board, IEP expressed its support for the withdrawn system power proposal and registered its opposition to the 15-day changes that removed it. Based on commissioned analysis, IEP contends that the emissions rate associated with power imported into California from a power supplier's particular system may actually be higher than the existing default rate applied to unspecified imports. IEP states that this fosters potential resource shuffling with some actual power imports being 16-40% higher than the default emissions rate. [T 07.01 — IEP]

Response: See Response to comment B-6a.

B-6q. System Power, Section 95111(a)(12).

Comment: SDG&E respectfully requests removal of the definitions for system power and system power supplier, §95102(a)(451) and (452) respectively, and associated provisions contained in sections 95111(a)(12), 95911(b)(5), and 95911(g)(6). These proposed changes to the MRR require an importer that obtains power from a supply entity akin to an asset controlling supplier, but having a higher emissions factor than the default emissions factor, to use ARB's published emissions factor for that supply entity rather than the default emissions factor. Section 95911(a)(12)(B) allows for electricity purchased as unspecified through a hub transaction to be reported as power unspecified, which conflicts with the above described requirement to use ARB's published emissions factor. It is unclear how an importer would prove the purchase as unspecified if the entity's e-tag shows up in a purchase. These provisions are confusing, would make verification extremely difficult, and should be deleted. [B 02.03 – SU]

Response: See Responses to comments B-6a and B-6d.

B-7. Default Emission Factor for Unspecified Power, Section 95111(b)(1)

Comment: Evidence Suggests That the Existing Default Emissions Factor Does Not Accurately Represent the Carbon Content of Power that is Imported Into California. IEP recently commissioned an analysis to determine whether the emissions rate associated with power imported into California from a power suppliers particular system may indeed be higher than the existing default rate applied to unspecified imports. The results of this analysis suggest this is the case. The analysis is appended to the IEP comments here, http://www.arb.ca.gov/lists/com-attach/35-ghg2013-B24BYlYnAAwCZ1U6.pdf

The attached analysis uses generation resources owned by Arizona Public Service Company (APS) and resources in the APS Power Control Area to compute a set of emissions factors to represent the emissions associated with power from the APS system, under various generation scenarios. In May 2013, APS established a policy that all generation exported to California will be labeled as “system” power. The analysis indicates that the range of APS specific system emission rates varies depending on which generation resources are included in the calculation. For example, one of the scenarios includes all of the generation (and associated emissions) owned by APS to calculate an emissions rate, while other scenarios may exclude renewable generation and/or nuclear generation from the calculation. APS was chosen as a point of reference due to its close proximity to California and the likelihood that power from the APS “system” will indeed be imported into California.

The analysis, which resulted in a range of emission factors for the combined resources owned by APS in both 2009 and 2012, concludes that the emissions rate associated with the power delivered to California from the APS system range from 0.5086 metric tons of carbon dioxide equivalent per megawatt hour ($MTCO_2e/MWh$) on the low end to 0.7196 $MTCO_2e/MWh$ on the high end, depending on the generation scenario. On the low end, the APS-specific emission factor is nearly 16% higher than CARB’s default rate. In all cases the emission rates for the APS system exceed the level of CARB’s default rate. On the high end, the APS-specific emissions factor is 40% higher than CARB’s existing default emissions rate of 0.428$MTCO_2e/MWh$.

In addition, as noted in the attached analysis, the U.S. Environmental Protection Agency’s Emissions and Generation Resource Integrated Database (eGRID) provides 2009 net generation and annual CO_2 equivalent emissions data for which an emission factor can be calculated for the entire APS Power Control Area (i.e. power in the APS control area, but not necessarily owned by APS). This data yields an emission rate for the APS Power Control Area of 0.8448 $MTCO_2e/MWh$; nearly double CARB’s default rate that is currently applied to unspecified imports. To put this in perspective, first deliverers importing system power into California are essentially paying about half of the GHG compliance costs that they would be required to pay if a system rate, based on the APS Power Control Area numbers from the eGRID, were employed. [OP 28.01 – IEP]

Response: ARB staff appreciates IEP’s consideration of the default emission factor, its role in our program, and the case study analysis. However, the default emission factor was not noticed in the 45-day notice, so this issue is outside the scope of the current rulemaking and ARB staff therefore declines to make any changes to this provision at this time.

B-8a. Guidance for Specified and Unspecified Power Claims, Section 95111(b)(1), (2)

Comment: Morgan Stanley states that it appreciates ARB’s ongoing ancillary effort to provide guidance documents that help market participants interpret the regulations, as they apply to practical everyday situations. With regard to electricity market transactions, Morgan Stanley suggests that ARB consider issuing a matrix chart, in the form of a guidance document, showing how all transaction types fit into the various reporting categories. Morgan Stanley recommends that ARB adopt the matrix included in their comments as part of its guidance document collection. [OP 01.07 – MSCG]

Response: ARB staff appreciates the suggested guidance matrix, but does not believe this is necessary to add into the reporting regulation. As evidenced by the Powerex comment in B-8b, such a matrix would have to be carefully developed and reviewed to ensure that it accurately reflects the regulatory requirements and includes specific citations to applicable sections. ARB staff will consider this in the future, potentially as guidance.

B-8b. Guidance for Specified and Unspecified Power Claims, Section 95111(b)(1), (2)

Comment: Powerex takes issue with item in the guidance matrix proposed by MSCG. In particular, Powerex disagrees with MSCG's proposed treatment of "*Day Ahead Transactions (Preschedule transactions up to a week)*" which MSCG would classify as "*ACS power - If power is generated from facilities located inside ACS balancing authority: Specified ACS emission rate*." According to Powerex, MSCG's proposal to rely on NERC e-Tags applies only to a subset of commercial arrangements and types of market participants. This treatment would not be applied to all sales by an ACS; only bilateral sales are affected. Moreover, bilateral sales by non-ACS entities would continue to require a written power contract contingent upon delivery from a designated source. The inconsistency between MSCG's proposal for bilateral ACS sales and the requirements that would continue to apply to other types of transactions is depicted below.

	Bilateral Transaction		**Exchange or Anonymous Broker**
	Contingent upon delivery of power from particular source	**Not contingent** upon delivery from particular source	
Specified Facilities	**Specified** *(Actual delivery verified via NERC e-Tag)*	**Unspecified**	**Unspecified**
Asset-Controlling Supplier	**Specified** *(Actual delivery verified via NERC e-Tag)*	**Unspecified**	**Unspecified**
		MSCG Proposed Exception: **Specified** *if NERC e-Tag shows source as ACS Balancing Authority*	

The red-bordered area indicates the special rule MSCG proposes to apply only to bilateral sales by an ACS. The proposal would create an artificial distinction between transactions by ACS and non-ACS entities, while simultaneously discarding the legitimate distinction between sales that are contingent upon delivery of power from a particular source and sales that are not.

See also the Powerex comments in B-2j on the seller control topic in this report.

Response: See Response to comment B-8a.

B-9a. Transparency of ACS Calculation, Section 95111(b)(3).

Comment: Morgan Stanley calls for greater transparency in the ACS program and system emission factor calculation. According to Morgan Stanley, nine months of real world experience with the cap-and-trade program have seen significant shifts in market activity attributable solely to the ACS status of certain entities, as opposed to the implementation of the cap-and-trade program itself. ACS entities can import specified or unspecified power and “sink” it in their host Balancing Authority, either directly or through an intermediary system, and then “regenerate” ACS power for direct delivery to California. California receives “low carbon” ACS power and the ACS importer is not required to retire carbon allowances, but clearly there has been no change in the overall carbon intensity of the generation, in aggregate. These shifts have led to widespread suspicion among market participants that ACS entities may be abusing the ACS process to “launder” dirty power. The best way to dispel (or confirm) this suspicion is through the most well-known disinfectant: sunshine. To this end, we reiterate two requests frequently made in prior commenting opportunities. First, we believe that the regulations should include a detailed narrative description of the philosophical underpinnings of the ACS program. Absent this benchmark, market participants have no standard against which to evaluate the appropriateness, or lack thereof, of any particular rule, regulation, practice or formula governing ACS activity. Second, we believe the details of all ACS emission rate calculations should be made public, so market participants can review and critique the results. In particular, market participants, with their expertise and “market intelligence”, may be well placed to identify issues, problems and abuses that ARB staff, without either market experience or market presence, could not reasonably be expected to identify. For these reasons, we strongly believe that the ongoing integrity of the cap-and trade program requires much greater transparency surrounding all aspects of the ACS program. [OP 01.03 – MSCG]

Response: See Response to comment B-9b.

B-9b. Transparency of ACS Calculation, Section 95111(b)(3).

Comment: PacifiCorp states that the rules should not allow for an ACS entity to import specified or unspecified power into its balancing authority “sink the generation” and then by an effective de-designation or non-designation, regenerate ACS energy and sell it at a different emission factor. The lack of a transparent and clear method for calculation of the ACS emission factor only further exacerbates the potential that ARB will have difficulty enforcing its rules outside of California or the United States. [OP 15.04 – PC]

Response: ARB staff appreciates the comments on ACS transparency from MSCG and PacifiCorp. The calculation for determining GHG emissions of imported electricity supplied by specified asset-controlling suppliers is set forth in section 95111(b)(3). Regarding MSCG’s concern that ACS entities can import specified or unspecified power and “sink” it in their host Balancing Authority, either directly or through an intermediary system, and then “regenerate” ACS power for direct delivery to California, ARB staff notes that this is not entirely correct. In a bilateral transaction for ACS power between the ACS entity and the buyer, the sale is for ACS power and would be tagged as such.

The ACS calculation contains both specified and unspecified purchased power components, as well as an owned-generation component. ACS entities may own a large majority of the generation resources in their portfolio, but they can and do purchase additional power from both specified and unspecified sources. Specified and unspecified power purchases by an ACS entity are absorbed into the ACS system and, aside from any specified source sales (captured by the “SEsp” component of the equation in section 95111(b)(3)), all ACS sales are from the ACS system.

To the extent MSCG is concerned that an ACS may be over-procuring high quantities unspecified or higher-carbon specified power for resale, ARB staff notes that the ACS calculation is based on reported and verified emissions data. An ACS that procures larger amounts of higher-carbon purchased power will have this increased procurement activity reflected in subsequent ACS calculations. So, for an ACS that “may be abusing the process to ‘launder’ dirty power” as surmised by MSCG, such procurement will be reflected in the ACS calculation for the next calendar year. Thus, there is a disincentive for an ACS to increase procurement of high-carbon power, and if they do, it will be reflected in their ACS factor.

With regard to the MSCG sunshine comment, that the regulations should include a detailed narrative description of the ‘philosophical underpinnings’ of the ACS program, as ARB staff has explained above, the details of the ACS calculation are already expressly set forth in the regulation, and actual ACS system emission factors are based on reported and verified data. Thus, a benchmark already exists, and market participants may use this standard against which to evaluate the program. The above response, along with staff’s responses to comments A-10, B-2a-l, B-3, B-4a-c, and B-5a-c addresses the comments raised by PacifiCorp.

B-10. <u>Deadline to Reconcile RPS Adjustment Claims, Section 95111(g)</u>

<u>Comment</u>: SCE. ARB should eliminate the 45-day deadline for reconciling electricity claimed in the RPS adjustment, effectively making the deadline the same as for the verification statement Section 95111(g) of the MRR states that: “Registration information and the amount of electricity claimed in the RPS adjustment must be fully reconciled and corrections must be certified within 45 days following the emissions data report due date.” This provision, which requires a due date of approximately July 15, is in conflict with other portions of the MRR, which allow modifications to the emissions data report to be made until the September 1 verification statement deadline.

Reconciling electricity claimed in the RPS adjustment is just like any other modification to the emissions data report, and thus should not have a separate, earlier deadline of 45 days after the emissions data report due date. A reporting entity should be able to submit and certify a revised emissions data report until the September 1 verification statement deadline that includes modifications to reconcile the amount of electricity claimed in the RPS adjustment. To maintain consistency in the schedule for emissions data reports referenced throughout the MRR, SCE recommends that the ARB eliminate the 45-day deadline for reconciling electricity claimed in the RPS adjustment, effectively making that deadline the same as the deadline for the verification statement. This change could be accomplished by deleting the following sentence in Section 95111(g) of the MRR:

> "~~**Registration information and the amount of electricity claimed in the RPS adjustment must be fully reconciled and corrections must be certified within 45 days following the emissions data report due date.**~~"

Alternatively, the ARB could revise the same sentence in Section 95111(g) as follows:

> "Registration information and the amount of electricity claimed in the RPS adjustment must be fully reconciled and corrections must be certified ~~**within 45 days following the emissions data report due date**~~**by the verification statement due date provided in section 95103(f)**."

[OP 21.04 – SCE]

Response: ARB staff understands the concern regarding the 45-day deadline for reconciling electricity claimed in the RPS adjustment. In practice, electric power entities must work with their verification bodies to ensure this information is added correctly by the verification deadline. The 45-day deadline is in place to ensure proper planning and data reconciliations regarding the RPS adjustment take place in a timely fashion in order to support the timing requirements of the MRR and provide sufficient time for verification. For this reason, ARB staff did not make the suggested edits to the MRR.

B-11a. Renewable Energy Credits (RECs) and RPS Adjustment, Section 95111(g)(1)(M).

Comment: WPTF. The RPS program requires that, for both portfolio content category one (procurement that corresponds to direct delivery of renewable electricity) and category two (for which the RPS adjustment may be applied) RECs generated by the eligible renewable resource must be matched to specific NERC e-tags to demonstrate either direct delivery in the former case, or delivery of substitute power in the latter. The Western Renewable Energy Generation Information System (WREGIS) provides a function that allows users to match specific RECs to specific NERC e-tags for scheduling of power. This matching can only be done by the entity with title to the REC as it is imported into California, and cannot be changed. LSEs must then provide this information in the form a "WREGIS NERC e-tag Summary Report" to the California Public Utilities Commission or the California Energy Commission to demonstrate that delivery requirements for procurement categories one and two have been met.

WPTF recommends that CARB expand provisions in the MRR to strengthen the verification of claims to the RPS adjustment and eliminate the requirement for REC retirement. Specifically, WPTF recommends that the importer be required to

demonstrate that the RECs associated with the renewable electricity generation have been matched to the appropriate NERC tags. This can be done by requiring importers to retain documentation of WREGIS matching of the associated RECs to e-tags for all renewable imports or claims to the RPS adjustment and to provide it upon request to verifiers. Importers can fulfill this requirement by providing the WREGIS NERC e-tag Summary Report for the LSEs on whose behalf they imported the power. This information can then be readily checked by a verifier.
[OP 02.07 — WPTF]

B-11b.Renewable Energy Credits (RECs) and RPS Adjustment, Section95111(g)(1)(M).

Comment: WPTF Supplemental Comments. WPTF would like to take this opportunity to provide additional comments to the California Air Resources Board (CARB) on the Renewable Portfolio Standard (RPS) Adjustment. In our earlier comments, WPTF highlighted the need for an entity importing substitute power on behalf of an RPS---obligated entity (a retail provider) to be able to claim the RPS adjustment. Additionally, we proposed that the regulation be modified to require an attestation by retail providers that Renewable Energy Credits (RECs) reported in association with the RPS adjustment will be retired for RPS program compliance, instead of requiring that these RECs be retired before the RPS adjustment can be used. We provide more detail on these issues below.

Use of the RPS adjustment by entities that are not retail providers: The current regulatory provisions do not permit use of the RPS adjustment by importers of substitute electricity that do not have ownership or contractual rights to the associated RECs. From conversations with staff, it appears that this is intentional based on staff expectation that retail providers will compensate importers of substitute energy for the carbon costs of that electricity, and that the retail providers will be able to recoup this additional cost by taking the RPS adjustment. While we agree with the intent of this approach – that the benefit of the RPS adjustment accrues to the retail provider, we note that it will not work for many existing contracts and for many retail providers. First, there are existing RPS contracts in place under which the retail provider's counter---party does not take title to the associated RECS, but is responsible for importing firming and shaping electricity and the counter---party is expected to use the RPS adjustment to cover the carbon cost (rather than the retail provider paying for the importer's carbon cost). These contracts would have to be re---negotiated if the importer is not able to take the RPS adjustment.

Second, we note that many small retail providers do not have a compliance obligation under the cap and trade program because they do not own in---state generation and are not first jurisdictional deliverers of electricity. Under the current regulation, these retail providers would not be able to take the RPS adjustment since they would have no emission obligation against which to apply the RPS adjustment. Yet these retail providers are subject to the RPS and will incur increased costs due to the carbon price embedded in their electricity purchases. In order to address this problem, it is critical for CARB to provide a mechanism to enable importers of firming and shaping power pursuant to a retail provider's RPS procurement to claim the RPS adjustment. We therefore propose that staff modify the regulation to allow the RPS adjustment to be taken either by the retail provider, or another entity designated by that retail provider to use the RPS adjustment on its behalf. [OP 30.01 — WPTF]

Attestation and reporting and verification of REC retirement: In our previous comments, WPTF proposed that, instead of requiring that RECs associated with the RPS adjustment be retired in order for the RPS adjustment to be used, the regulation should require an attestation from the retail provider that the RECs reported in association with the RPS adjustment would be retired for that entity's RPS compliance. To facilitate staff consideration of this proposal, we provide additional recommendation on the language for such an attestation, as well as how the retirement of associated RECs could be reported and verified.

- As part of its annual report, each retail provider wishing to use the RPS adjustment would be required to submit an attestation that states: *"I certify under penalty of perjury that I am duly authorized by [name of entity] to sign this attestation on behalf of [name of entity] and that [name of entity] shall retire all RECs reported herein in association with the RPS adjustment for RPS compliance within 36 months of generation."*

- Each retail provider would have the option to designate other entities (i.e. importers of incremental power on the retail provider's behalf) that may use the RPS adjustment on behalf of that retail provider. In order to use this option, the retail provider must identify the other entity, the other entity's designated quantity of RPS Adjustment and the RPS project ID of the resource from which the renewable energy was procured. o CARB staff would provide verifiers with a list of entities authorized by retail providers to use the RPS adjustment, and the associated RPS project IDs o Other entities that are authorized by retail providers to use the RPS adjustment on the retail provider's behalf must enter the RPS project ID on the NERC tag for the delivered electricity, consistent with RPS program rules.

- CARB should develop a template for reporting by retail providers of the serial numbers and vintages of RECs reported in association with the RPS Adjustment, including those for which another entity has been authorized to use the RPS adjustment. (We note that the MRR already requires reporting of REC serial numbers, but no template has been provided.) Reporting of the vintage of RECs would enable CARB staff and verifiers to determine the deadline for retirement in accordance with RPS program rules. For example, a February 2012 vintage REC must be retired by February 2015.

- In its annual report, each retail provider must include information on RECs claimed for the RPS adjustment for the previous reporting year, and provide an update on the status (retired or non---retired) of previously reported RECs that were not retired at the time the RPS adjustment was claimed. • As part of the verification of retail providers annual reports under the MRR, verifiers would spot---check reported REC retirement. Retail providers can document REC retirement by providing the verifier with a copy of their WREGIS retirement account holdings. • In the case that another entity has been authorized by a retail provider to use the RPS adjustment, verifiers would check that the entity can document that NERC tags contain the appropriate RPS project ID. [OP 30.02 — WPTF]

B-11c. Renewable Energy Credits (RECs) and RPS Adjustment, Section 95111(g)(1)(M)

Comment: **SCE**. During ARB's July 18, 2013 workshop, SCE again raised the issue of REC retirement for the RPS adjustment because the proposed regulation language remained unclear. SCE was pleased that the ARB clarified that the regulations allow the RPS adjustment for out-of-state renewable energy that is not imported into California, as long as the corresponding RECs are deposited in the Western Renewable Energy Generation Information System ("WREGIS") "retirement subaccount" in the year they were generated, even though the actual retirement of such RECs for RPS compliance purposes may occur later (within the RPS compliance window set by the California Energy Commission). This is an important clarification because the ARB's language 19 previously suggested that in order to claim the RPS adjustment, the retirement for compliance with the RPS program must also occur during the same year in which the RECs were created. SCE greatly appreciates this clarity and urges the ARB to make changes in its final regulations reflecting the clarification provided by Staff. Specifically, SCE suggests the following change to Section 95852(b)(4)(B) of the cap-and-trade regulation:

The RECs associated with the electricity claimed for the RPS adjustment must be placed in the retirement subaccount of the entity party to the contract in 95852(b)(4)(A), in the accounting system established by the CEC pursuant to PUC 399.13 ~~**and designated as retired for the purpose of compliance with the California RPS program**~~ ~~used to comply with the California RPS requirements~~ during the same year ~~in~~ for which the RPS adjustment is claimed (and during the year in which those RECs were created). **The RECs must be designated as retired for the purpose of compliance with the California RPS program on a schedule consistent with the rules governing that program.**

Response: (This response addresses comments B-11, a-c) Staff has not proposed any amendments to section 95111(g)(1)(M). As such, the commenter's requested changes are beyond the scope of the current rulemaking. Notwithstanding this, ARB staff notes that while the RPS Adjustment and the issue of REC retirement requirements are addressed in the MRR, these are addressed in more detail in the Cap-and-Trade regulation. Modifications to the reporting of RECs were not noticed in the 45-day Notice, so the comments are outside the scope of this rulemaking. However, ARB staff will continue to work with stakeholders to determine whether developing a more uniform REC reporting template consistent with the regulatory requirements is appropriate.

B-12a. Meter Generation Data

Comment: WPTF recommends that ARB retain the language "at the time the power was directly delivered" in the Section 95111(g)(1)(N) meter data requirement. WPTF has long understood that the specification of electricity imports requires a clear nexus between (a) actual generation of power from the resource in question, (b) direct delivery of power from the resource into California, and (c) the contractual or ownership right of the reporting entity to claim that power. Elimination of meter data provision in question would result in over-accounting of low-emission generation.

The ISOR explains that staff deleted this language based on the understanding that "it is common practice in the industry to perform monthly true-ups between generated and scheduled power." ARB is correct that it is common practice to perform monthly true-ups of generated and scheduled power, particularly for renewable electricity. These monthly true-up typically provide a comparison of hourly meter and schedule data, which is then aggregated to total any discrepancies over the month. Thus, the practice of monthly true-up is not incompatible with the regulatory requirement that specified electricity be generated at the time of delivery, but rather supports industry implementation of this requirement. [OP 02.06 – WPTF]

Response: ARB staff has withdrawn the 45-day proposal to remove this language and has included it back in the proposed 15-day modifications. ARB staff determined that maintaining meter generation at the time the power was generated is consistent with the current reporting requirements in MRR and other California programs, such as the Renewable Portfolio Standard (RPS) program under Senate Bill X1 2 ("SBX1 2"). The RPS regulation 3203(a)(1)(C) states that, "If there is a difference between the amount of electricity generated within an hour and the amount of electricity scheduled into a California balancing authority within that same hour, only the lesser of the two amounts shall be classified as Portfolio Content Category."

Based on the above explanation, ARB staff agrees with the WPTF recommendation that ARB retain the language "*at the time the power was directly delivered*" in the Section 95111(g)(1)(N) meter data requirement. ARB staff also appreciates the clarification from the commenter regarding how the monthly true up relates to hourly generation data. It is clear from this comment that hourly generation is needed to accurately complete the monthly true-up. Lastly, ARB staff appreciates the comment regarding the data collection burden of this requirement. It seems that hourly data is already needed for the financial settlement of electricity transactions.

B-12b. Meter Generation Data

Comment: WPTF addressed the Board on the meter data issue. WPTF welcomes the staff proposal to reinstate language that would require retention of meter data to demonstrate that electricity was generated by a specified resource at the time that electricity is delivered to California. Throughout the evolution of this regulation, CARB staff has consistently strived to ensure the accuracy of reported emissions. Elimination of the language requiring matching of generation to delivery would undermine this objective and result in over-counting of low-emission imports. When electricity is scheduled for delivery from a generating resource via a NERC tag, the balancing area in which the generator is located typically commits to provide 'contingency reserves'. This means that in the event that a committed generator is unavailable in an hour, the host balancing area will provide energy from its' own system to ensure that the volume of the schedule is met. In this situation, the volume of delivered electricity exceeds the volume of electricity actually produced by the generator in that hour. In recognition of this, both the California Public Utilities Commission and the California Energy Commission require that for Renewable Portfolio Standard procurement category that is direct delivery of renewable energy – only the lesser of generation or scheduled delivery may be counted toward the RPS targets.

WPTF believes that the same approach should be used under the greenhouse gas reporting program to ensure that the accounting of renewable imports under the cap and trade program will be accurate and will align with that under the RPS program. We also recommend that this approach be applied symmetrically to all imported electricity – not just renewable electricity. To do otherwise would be discriminatory to renewable generation, as it would apply a stricter standard for renewable imports than for other low emission imports. Because generation meter data is already collected and utilized for financial settlement of electricity transactions, requiring importers to retain such data to document that the imported electricity was generated by the facility at the time the power was directly delivered does not create a significant burden on generators or importers. [B 03.01 – WPTF]

Response: See response to comment B-12a.

B-12c. Meter Generation Data

Comment: WPTF reiterated the comments in B 03.01 in their testimony at the board hearing
[T 12.01 – WPTF]

Response: See response to comment B-12a.

B-12d. Meter Generation Data

Comment: SCPPA commends the ARB for deleting the phrase "at the time the power was directly delivered" in section 95111(g)(1)(N) and providing that this change will take effect for 2013 data reported in 2014 (section 95103(h)(8)). Requiring hourly meter generation data was problematic for several reasons. Some existing contracts for specified source electricity do not contain provisions allowing the purchaser access to the hourly meter data. Even if the information was available, tracking and verifying so much detailed data would have required a significant amount of additional time. Furthermore, any imbalance that occurs between the electricity generated and the electricity delivered is typically trued-up as part of the contract administration and energy reconciliation process. Finally, the reports under the Regulation are annual, so accuracy on an hourly basis should not matter provided that the annual figures provided in the report are accurate. Reported annual imports can be verified by comparing the figures with the reporting entity's share of the generating facility's annual generation meter data. For these reasons, SCPPA supports the proposed change to section 95111(g)(1)(N) and considers that no further changes need to be made to this subsection. [OP 12.09 – SCPPA].

Response: ARB staff thanks the commenter for support in initially removing the requirement, but notes that it was added back in during the proposed 15-day modifications. From the perspective of ARB staff, it is not clear why some contracts would not allow a purchaser to view the data on the power they have received. Additionally, it seems that the commenter's concerns about additional burden may not be well-founded because it is staff's understanding that this information is needed for other California programs, as well as being existing regulatory requirements under the MRR. Lastly, ARB staff disagrees that accuracy at the hourly level does not matter. The electricity importer requirements are based on e-tags, which are developed at the hourly level. Although the emissions data report is an annual report, in order to support the validity of the annual values, hourly data that verifies the information on the NERC e-tag is also necessary. ARB staff notes the requirements to retain the meter generation data for verification purposes are already part of the existing MRR requirements. Additionally, see response to comment B-12a for more information.

B-12e. Meter Generation Data

Comment: SCPPA opposes the 15-day change on the hourly meter data issue. [T 01.04 – SCPPA]

Response: See response to comment B-12d.

B-12f. Meter Generation Data

Comment: MSR states that the proposed amendments properly remove hourly meter data requirements. As amended, "at the time the power was directly delivered" would be stricken from section 95111(g)(1)(N). M-S-R supports the proposed revision to the Regulation and urges the Board to adopt the change. As more fully set forth in the comments submitted by the Los Angeles Department of Water and Power, an hour by hour comparison of meter and e-tag data for all specified imports (including non-renewable resources, since subsection (g) does not apply solely to renewable resources) would be a significant labor burden for reporting entities, such as the members of M-S-R. Not only would additional data need to be collected and reported, but it would then be subject to verification, which would result in increased compliance costs for reporting entities. M-S-R appreciates the proposed amendment and urges the Board to adopt it. [OP 31.03 – MSR]

Response: See responses to comments B-12a and B-12d.

B-12g. Meter Generation Data

Comment: M-S-R opposes the 15-day change for hourly meter data.
[T 06.03 – MSR]

Response: See responses to comments B-12a and B-12d.

B-12h. Meter Generation Data

Comment: TID states that the MRR currently requires covered entities to retain meter data from specified sources for purposes of verification. Based on recent discussions with ARB staff, TID understands that the ARB wants electricity importers to conduct an hour-by-hour comparison between the generating facility meter data and the MWh on the e-tag, and to report specified imports as the lesser of the meter or the MWhs on the e-tags for each hour. TID is concerned that such a comparison would create a significant administrative burden both for the reporting entity and the verifier. Depending on the number of imports involved and the number of e-tags generated in a single day, it could take weeks for staff to complete this comparison. In some cases, tags might need to be split, and as a result, it would be difficult for a verifier to recreate the covered entity's analysis. This additional burden would not outweigh the benefit to the ARB of having more accurate data. In almost all cases, the metering data will be consistent with the e-tags and any minor improvement in reporting accuracy would be significantly outweighed by the administrative burden on reporting entities and their verification costs. The ARB's proposed change to Section 95111(g)(1)(N) helps address these concerns by limiting the hour-by-hour comparison. TID therefore strongly supports the ARB's proposed change to Section 95111(g)(1)(N.
[OP 33.03 – TID]

Response: As the commenter indicated, the meter retention requirement is already part of the existing MRR requirements, so it is unclear how this already-existing requirement would be an increased administrative burden. To the extent the administrative burden may increase, ARB staff is committed to assisting the reporting entities, as needed, by developing supplemental guidance on this topic. ARB staff notes that complete and accurate reporting is essential for the success of ARB's reporting program and to support the Cap-and-Trade Program. Additionally, see responses to comments B-12a and B-12d.

B-12i. Meter Generation Data

Comment: TID opposes the 15-day change for hourly meter data, and states that it could create an administrative burden for smaller POUs. [T 04.01 – TID].

Response: See response to comment B-12h.

B-12j. Meter Generation Data

Comment: LADWP states that, for the purpose of verifying specified electricity imports, it is useful to compare the Electric Power Entity's share of the annual net generation from a specified generating facility or unit with the annual quantity of electricity claimed as specified in the entity's annual report.

LADWP supports the proposed amendment to remove "at the time the power was directly delivered" from this section of the rule for the following reasons:

1. The Electric Power Entity GHG emissions report to CARB is an annual report; therefore, it should be sufficient to verify that the amount of renewable energy generated on an annual basis corresponds with the amount reported to ensure that directly delivered renewable energy imports are not over- or under- stated in the annual report. Any imbalance between the electricity generated and the electricity delivered is trued-up as part of the energy reconciliation process. Accuracy on an hourly basis (i.e. whether the electricity was generated "at the time the power was directly delivered") is not necessary for an annual report.

2. It is not practical to compare hour by hour generating facility meter and e-tag data and report the lessor of the two for the following reasons:

   a. Meter and e-tag data will never match, because the unit of measure for meter data is kWh and e-tags are in MWh. In addition, meter data may not account for station service, transformer and line losses.
   b. Preparing the meter and e-tag data to be able to do an hour by hour comparison requires a great deal of data manipulation with a significant potential for making errors.
   c. Comparing hour by hour meter and e-tag data is very labor intensive. The difference between the hourly meter and e-tag is well below ARB's 5% accuracy threshold.

d. It would be difficult to verify with reasonable assurance that the lessor of the meter or the e-tag data for 8,760 hours for every specified import is accurate.

3. Having to report and verify hourly data for an annual report is impractical and time consuming, and would divert limited resources away from the more significant elements of the report. There are better ways to verify that the amount of renewable energy generated corresponds with the amount delivered, such as comparing annual generating facility meter data with the annual reported number. Verifying hourly data would add a significant burden to both reporters and verifiers without adding value.

Therefore, LADWP supports removal of the phrase “at the time the power was directly delivered” from 95111(g)(1)(N). [B 01.08 – LADWP].

Response: As noted in the other responses, ARB staff has added this requirement back into the reporting regulation as part of the proposed 15-day modifications (see response to comment B-12a). As described in response to comment B-12d, ARB staff does not agree with the commenter’s remark on the annual report. ARB staff is aware the report is annual, but the data that comprise the annual values is based on NERC e-tags, that developed at an hourly rate. Therefore, during verification, hourly information is needed to demonstrate accuracy to the verifier for the case of NERC e-tags.

In the second part of this comment, the commenter presents information that shows why an hour-by-hour comparison is not practical. Staff responses are shown below:

a. ARB staff believes the matching of meter generation and e-tag data is straightforward for a reporting entity or a verifier to perform a unit conversion. The reporting regulation has provisions for correcting for transmission losses and this is also straightforward to factor into the overall comparison.

b. ARB staff understands there are many complexities for each sector that reports under the reporting regulation. However, tracking at the hour level is not a new reporting requirement and that each reporting entity should have been doing this already. Lastly, a robust QA/QC evaluation and data automation should eliminate the potential errors from manipulation of large data sets.

c. At the Board meeting, the commenter testified that the difference was about 1.65 percent between what was reported by LADWP and the hourly comparison. While this does not constitute a material misstatement during verification, it still would result in a qualified positive verification statement because the reporting requirements were not adhered to.

d. ARB staff agrees with the commenter on this point. However, the job of the verifier is not to demonstrate absolute assurance, but instead demonstrate reasonable assurance. In a verifier’s sampling plan, they have the discretion to identify the data they deem is necessary to evaluate. This will likely not include all of the commenter’s specified sources, but a representative sample to develop reasonable assurance the data is accurate.

Lastly, the commenter indicates that this would place undue resources on this issue from the reporting and verification perspective. ARB staff disagrees with this statement because, as mentioned above, the e-tags are hourly, so, in order to demonstrate accuracy the meter generation data must match the e-tag.

B-12k. Meter Generation Data

Comment: Commenter testified their opposition to the 15-day change for hourly meter data, during the board hearing. [T 05.01 – LADWP]

Response: See response to comment B-12j.

B-12l. Meter Generation Data

Comment: Shell Energy stated, in oral comments before the Board, that it supports the retention of the language in section 95111(g)(1)(N), "at the time the power was directly delivered," which the 45-day draft had proposed for removal. Shells stated that retaining this language in the MRR will result in more accurate emissions accounting. [T 11.01 – SE]

Response: See response to comment B-12a.

B-12m. Meter Generation Data

Comment: SMUD stated, in oral comments before the Board, that it supports the proposed removal of the meter data requirement set forth in the 45-day draft because metered generation and transmission schedules do not always match up for operational reasons, and for reasons stated by previous POU commenters. [T 15.02 – SMUD]

Response: See responses to comments B-12a and B-12d.

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

§95112 – Electricity Generation and Cogeneration Units

C-1. Modify Scope of New Requirements for Power Generators

Comment: Several of the proposed amendments are aimed to provide transition assistance for "legacy" contracts and evaluate "but for" CHP. EPUC/CAC requests modification of the amendments to make clear that cogeneration facilities that are not seeking these forms of assistance do not need to provide the associated data. Subjecting cogenerators that are neither "legacy" nor "but for" generators to these new requirements provides no new valuable information to CARB while subjecting the generators to additional reporting requirements and costs.

1. *Changes to §95112 (a) Are Designed to Capture the Information Needed to Implement Legacy and "But for" Amendments* Staff have proposed amendments to the Cap-and-Trade (C-T) Regulation that would provide assistance to those generators subject to legacy contracts that do not provide for GHG compliance costs. Staff also proposes that facilities that would not have a compliance obligation "but for" their investment in CHP will be exempt from compliance obligation through 2014. To implement these changes, amendments to the MRR are required in order to gather information on energy disposition and assess carbon cost pass-through, information that is necessary only for providing Legacy Contract Generator assistance or assessing "but for" status.

a. Amendments to §95112(a) Will Help Staff Gather Necessary Information to Implement the New Cap and Trade Provisions.

Staff proposes multiple changes to §95112 (a) in order to gather the additional information required to implement Legacy Contract and "but for" limited exemption provisions:

- In Section (a), Staff indicates that in order to receive legacy contract assistance facility operators must always provide the information required in §95112(4)-(6) which is otherwise optional for facilities that do not sell energy outside of the facility boundary.

- In Section (a)(4) and (a)(5), Staff proposes to add headings to clarify the proper reporting of energy flows by disposition category.

- Staff proposes that it will amend (a)(4)(C) and (a)(5)(C) to gather additional information on the "*system energy balance,*" specifically the generated electricity and generated thermal energy used to produce cooling energy. Additionally, if a facility includes more than one cogeneration system and generates qualified thermal or electricity for more than one disposition, the facility must report the dispositions aggregated by unit with the same disposition.

It appears that Staff proposed the changes required to address Legacy Contract Generators and "but for" CHP overlooking the fact that other facilities must comply with §95112(a)(4) and (5). It is not clear from the language of the Initial Statement of Reasons (ISOR) or changes to the MRR and Cap-and-Trade regulation otherwise that staff intended all generators selling outside of their boundary to provide this information. As written, however, all generators subject to §95112(a) (4)-(6) are subject to these new requirements.

b. The ISOR and Statutory Language Demonstrates the Staff Intent to Limit Additional Regulatory Requirements.

The language of the ISOR does not suggest that it was the intent of Staff to apply new requirements outside of Legacy Contract Generators. This information is not required to assess the compliance requirements of other facilities, and represents a new cost of compliance with no corresponding benefit for the generator or CARB.

The ISOR rationale suggests that the changes to (a) as well as (a)(4) and (a)(5) are all required to gather the data needed in order to assess "*carbon cost pass-through*," and to make allocations to Legacy Contract Generators. Specifically, the ISOR indicates that when generated thermal energy or electricity is provided to multiple end-users, the disposition information requested "*provides key information for assessing **carbon cost pass-through** from the electricity generator to the purchasers of the generated electricity*." The Proposed Solution to the Problem explanation in the ISOR further supports the EPUC and CAC reading of Staff's intent. The proposed revision "*enables the assessment of **carbon cost pass-through** from the cogen facility operator to their thermal hosts, separately from other units that are not part of the same cogen system.*" Carbon cost pass-through information is relevant information for providing assistance to Legacy Contract Generators and "but for" CHP, and the new data requirements should be so limited.

While the stated intention for changes to §95112(a)(5)(C) is to clarify reporting and complete system energy balances, the definition of "Qualified Thermal Output" suggests that Staff also intends to use the new data collected to determine "but for" CHP. The definition specifies that Qualified Thermal Output, energy generated using cogeneration and used by on-site industrial processes, is to be reported in MRR §95112(a)(5)(C). The only use of the term Qualified Thermal Output in the Cap-and-Trade Regulation is in connection with providing a limited exception to "but for" CHP (§ 95852(j)). The C-T ISOR confirms this reading, stating the "*definition is needed to clarify the kind of thermal output that will be used to determine the eligibility of a facility for a facility with a cogeneration unit or a district heating facility for a limited exemption for emissions associated with thermal energy production pursuant to section 95852(j)* (see attachment to the letter for more information).

c. The Impact of the Proposed Changes Should Be Limited to Legacy Contract Generators and But For CHP.

Non-Legacy or but for CHP facilities should not be required to provide the information requested in §95112(a)(4)(C) and (a)(5)(C): the energy used to produce cooling energy and the disposition of energy by unit for multiple unit facilities. If the intent of the changes and the additional regulatory requirements in §95112 is to provide assistance to Legacy Contract Generators and identify "but for" CHP, the new requirements should be limited to those facilities. Providing this information will be an additional burden for facilities, without providing any additional useful information to CARB. If the information does not help CARB provide assistance or determine compliance requirements, the cost of providing the information will always outweigh the benefit of providing it.

d. The Clarification Can Be Addressed Using the Reporting Tool

The simplest means of addressing the drafting error is in the regulatory reporting tool. The tool could ask if a facility is seeking Legacy Contract Assistance or a "but for" CHP exemption. If yes, the additional information required by §95112(a) will be required, if not, the facility does not need to provide information regarding the energy used to produce cooling energy or its energy disposition by source.

If the Commission would rather address the drafting error in the MRR the proposed amendment should be modified to include the additional information required as subsections of §95112(a)(4)(C) and (a)(5)(C). Specifically, the commenter requests the following sentence be added at the end of 95112(a): "Only those facility operators applying for legacy contract transition assistance or a limited exemption of emissions from the production of qualified thermal output must comply with section 95112(a)(4)(C)(1)-(2) and section 95112(a)(5)(C)(1)-(2)." Since there are two buckets of information being requested each should be included as a subsection. After the information is set apart, §95112(a) should be amended to clarify that only "but for" CHP and Legacy Contract Generators are required to provide the additional information in these subsections. [OP 34.01 – EPUC/CAC]

Response: EPUC/CAC's interpretation is correct. The changes to sections 95112(a)(4) and (a)(5) apply to all electricity generators that meet the applicability criteria for the additional energy breakouts as specified in the rule text. The new requirements do not apply to any electricity generators that do not meet the applicability criteria specified in the rule. The changes to sections 95112(a)(4) and (a)(5) are designed to capture generated energy streams that were not previously broken out. Without these rule changes, a facility operator that provides cooling or distilled water to an off-site end-user would not be able to completely report their facility energy balance, and ARB staff would not be able to accurately split the emissions among the processes and products. These rule changes apply to any facilities that meet the applicability criteria specified in the rule text, regardless of whether the facility operators are applying for the "but for" exemption or the legacy contract assistance. These new requirements do not affect most of the electricity generators or cogenerators. Therefore, the impact of these new reporting requirements is expected to be very limited and ARB staff declines to make any modifications to the regulation or to Cal e-GGRT based on the comments from this commenter.

C-2. Reporting Data for Electricity Generators

Comment: Staff proposes changes to MRR §95112(b)(3) that clarify the meaning of total thermal output and seemingly as a check on the information required under §95112(a)(5). The amendments to require facilities to provide information on energy that "can be potentially utilized in other industrial operations that are not electricity generation." Additionally, the changes clarify that "the total thermal output quantity represents the amount of generated thermal energy that can be provided to the thermal energy disposition categories in section 95112(a)(5)."

The statement that the number provided in §95112(b)(3) should reflect the generated thermal energy provided in §95112(a)(5) suggests that the amendment is designed as a check on other information provided. The ISOR states, however, that these changes

are “made in response to reporter and verifier questions received during program implementation.” It is important that the reporting tool reflect the ISOR explanation of the change. To the extent that this is simply a clarification, there should be no further information required from facilities. If different or further information is required, Staff should provide additional explanation of the purposes of these changes.
[OP 34.02 – EPUC/CAC]]

Response: The proposed amendments were made in order to ensure the emissions and mass balance data reported under these sections is accurate. The proposed language under section 95112(b)(3) was clarification language. The proposed language in section 95111(a)(5)(C) is a new requirement and is designed to support the reporting of generated thermal energy. ARB staff is committed to ensuring the necessary modifications are made in Cal e-GGRT to support these changes and will plan on working with reporting entities early next year to ensure they understand the changes in the reporting tool.

C-3. Clarification for Facilities That Generate Their Own Thermal Energy And Uses the Energy Within the Facility

Comment: ARB proposes new amendments that state if a facility includes more than one electricity generating unit or cogeneration system and each unit/system or each group of units generate electricity for different particular end-users or retail providers or electricity marketers, the operator must separately report the disposition of generated electricity by unit/system or by group of units.

Recommendation:
Similar to our comments described above for Section 95104(d)(4), ARB should clarify that if a facility generates its own thermal energy within the facility boundaries and the thermal energy is used by the same company within its own on-site industrial processes then the operator can report the total amount of thermal energy as a total..
[OP 08.10 – WSPA]

Response: See response to comment A-43.

D. Subarticle 2. Petroleum Refineries and Hydrogen Production

(§95113 – §95114)

§95113 – Petroleum Refineries

D-1. Miscellaneous CWB issues

Comment: Chevron suggest the following changes be made to the CWB factor table:

- Fuel gas sales and treating should be reported in hp, not hp/yr as shown in the proposed table of CWB Values. This factor is based on the size of the equipment, not how much it was actually used during the year. This is a reasonable simplification, since the CWB factor incorporates an assumed utilization based on Solomon’s global data regarding refinery operations.

- Sulfur production should be reported in long tons not light tons. A light ton is not a recognized unit of measure.

- There are a few process units where the feed to one unit is NOT reported separately but is combined with another unit. For example, ‘tail gas recovery unit’ is already included in the sulfur recovery unit and should not be reported again—this is not explicitly in the May 17 document but was stated elsewhere by Solomon. The whole definition seems to be missing from the list provided by ARB on October 7.

- The footnotes to Appendix D of the May 17 document are not precisely included in ARB definitions.

    - The first footnote is about lubricants. ARB did not include the lubricants section from definitions in the May 17 document but instead broke out each of the lubricant processes. It would be preferable to include the lubricants as shown in the definitions.

    - The footnote about hydrogen plants should be included, and there should be a definition of ‘hydrogen plant.’ [OP 10.05 – CC]

<u>Response:</u> ARB staff has met with the stakeholder to go over their comments regarding the complexity weighted barrel. Below is a list of responses to their specific issues:

Fuel Gas: ARB staff agrees with this amendment and it was made as a 15-day modification.

Sulfur Production: ARB staff agrees with this amendment and it was made as a 15-day modification.

Tail Gas Recovery Unit: ARB staff agrees with this clarification and has removed the line-item explicitly referring to “tail gas recovery unit” and instead classified it as a process subtype under “Sulfur Recovery.”

Lubricants and Hydrogen plant: The suggested changes to these terms were not made. To maintain consistency with the disaggregation within the carbon dioxide weighted tonne throughputs, ARB did not make the suggested lubricant edit. The hydrogen plant term was not added because there is not a complexity weighted barrel throughput for hydrogen production. Therefore, the change is not needed.

D-2 Complexity Weighted Barrel Support Language

Comment:

A. Mandatory Reporting and Recordkeeping (MRR) for Complexity Weighted Barrel WSPA appreciates and supports ARB's proposal at their October 7, 2013 workshop to use Complexity Weighted Barrel (CWB) instead of the Carbon Weighted Tonne (CWT).

   Recommendation: WSPA supports staff's proposal to use CWB instead of CWT and, in so doing we recommend that ARB make all necessary revisions/corrections in support of CWB in their Mandatory Reporting Regulation, the Cap & Trade Regulation, Proposed Amendments to the MRR regulation (45-day draft), and all other related guidance and reference documents as appropriate. [OP 08.01 – WSPA]

B. WSPA supports Complexity Weighted Barrel. A key change was to propose the use of the Complexity Weighted Barrel (CWB) instead of the Complexity Weighted Ton (CWT) index that was used in Europe. WSPA strongly supports that change because the CWB methodology is appropriate for facilities in California because they measure throughput(s) in barrels rather than tons. [OP 23.01 – WSPA]

C. Language to Support Complexity Weighted Barrel (CWB)

   Earlier this month, ARB provided a document titled "Language to support Complexity Weighted Barrel (CWB)" that describes regulatory language and definitions needed to support adoption of CWB. We support the change to CWB and acknowledge the work ARB has done to implement the CWB index in California. In reviewing the ARB document, WSPA noted technical changes in ARB's proposed definitions that are necessary to ensure equitable and clear implementation of the CWB.

   In order to assist ARB in making the appropriate changes, WSPA is submitting proposed revisions in strike-out and underline format (Attachment B: Definitions Needed to Support CWB).

Attachment B: "Language to Support Complexity Weighted Barrel (CWB)

Page 1

To the equation for CWB, the CWB functions for Offsites and Non-energy utilities and Non Crude Sensible Heat need to be added.

Page 2 (E) Add, ...CWB function, however it is recognized that total process CWB, total input, and total non-crude input are used to calculate CWB for "off-sites and non-energy utilities" and "not crude sensible heat."

Page 6 – Units for sulfur recovery should be "thousands of long tons/year"

Page 8 – Units for Fuel Gas Sales Treating and Compression (hp) should be hp, not hp/year

Definitions

"Complexity weighted barrel" or "CWB" means a metric created to evaluate the greenhouse gas efficiency of petroleum refineries and related processes. The CWB value for an individual refinery is calculated using actual refinery throughput to specified process units and emission factors for these process units. The emission factor is denoted as the CWB factor and is representative of the greenhouse gas emission intensity at an average level of energy efficiency, for the same standard fuel type for each process unit for production, and for average process emissions of the process units across a sample of refineries. Each CWB factor is expressed as a value weighted relative to atmospheric crude distillation.

Process Definitions

☐ "Air separation unit" means a refinery unit which separates air into its components including oxygen. It is usually cryogenic but factor applies to all processes cryogenic or otherwise.

☐ "Alkylation/poly/dimersol" means a range of processes transforming C3/C4/C5 molecules into gasoline ~~C7/C8 molecules~~ over an acidic catalyst. This can be accomplished by alkylation with sulfuric acid or hydrofluoric acid, polymerization with a C3 or C3/C4 olefin feed, or dimersol.

☐ "Ammonia recovery unit" means a refinery unit in which ammonia-rich sour water stripper overhead is treated to separate ammonia suitable for sales or reuse in the refinery, in particular for the reduction of NOx emissions. This unit is the second stage of a two stage sour water stripping unit. The ammonia recovery unit includes, but is not limited to, the adsorber, stripper and fractionator.

☐ "Aromatic saturation of distillates" means the saturation of aromatic rings over a fixed catalyst bed at low or medium pressure and in the presence of hydrogen. ~~This process includes the desulfurization step which should therefore not be accounted for separately.~~

☐ "AROMAX®" means a special application of catalytic reforming for the specific purpose of producing light aromatics.

☐ "Aromatics production" means extraction of light aromatics from reformate and/or hydrotreated pyrolysis gasoline by means of a solvent.

☐ "Asphalt production" means the processing required to produce asphalts and bitumen, including bitumen oxidation (mostly for road paving). Asphalt later modified with polymers is included.

☐ "Atmospheric Crude Distillation" means primary atmospheric distillation of crude oil and other feedstocks. The atmospheric crude distillation unit includes any ancillary equipment such as a crude desalter, naphtha splitting, gas plant and
~~**Language to Support Complexity Weighted Barrel (CWB)**~~
~~10~~
wet treatment of light streams for mercaptan removal. Some units may have more than one main distillation column.

☐ "Benzene saturation" means selective hydrogenation of benzene in gasoline streams over a fixed catalyst bed at moderate pressure.

☐ "C4 isomer production" means conversion of normal butane into isobutane over a fixed catalyst bed and in the presence of hydrogen at low to moderate pressure.

☐ "C5/C6 isomer production - including ISOSIV" means conversion of normal paraffins into isoparaffins over a fixed catalyst bed and in the presence of hydrogen at low to moderate pressure. ~~Throughputs of this unit include the throughput of both once-through and recycle units.~~

☐ "Conventional naphtha hydrotreating" means desulfurization of virgin and cracked naphthas over a fixed catalyst bed at moderate pressure and in the presence of hydrogen. For cracked naphthas this also involves saturation of olefins.

☐ "Cryogenic LPG recovery" means a refinery unit in which liquefied petroleum gas (LPG) is extracted from refinery gas streams through cooling and removing the condensate heavy fractions. The processes and equipment for this unit include, but are not limited to, refrigeration, drier, compressor, absorber, stripper and fractionation.

☐ "Cumene production" means alkylation of benzene with propylene.

☐ "Cyclohexane production" means hydrogenation of benzene to cyclohexane over a catalyst at high pressure.

☐ "Delayed Coker" means a refinery unit which conducts a semi-continuous process, ~~similar in line-up to a visbreaker,~~ where the heat of reaction is supplied by a fired heater. Coke is produced in alternate drums that are swapped at regular intervals. Coke is cut out of full coke drums ~~and disposed of~~ as a product. For the purposes of analysis, facilities include coke handling and storage.

☐ "Desalination" means a refinery's desalination of sea water or contaminated water. It includes all such processes.

☐ "Desulfurization of C4–C6 Feeds" means desulfurization of light naphthas over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen.

☐ "Desulfurization of pyrolysis gasoline/naphtha" means selective or non-selective desulfurization of pyrolysis gasoline (by-product of light olefins production) and
~~Language to Support Complexity Weighted Barrel (CWB)~~
~~11~~
other streams over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen.

☐ "Diolefin to olefin saturation of gasoline" means selective saturation of diolefins over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen, to improve stability of thermally cracked and coker gasolines.

☐ "Distillate hydrotreating" means desulfurization of distillate ~~virgin kerosene~~ over a fixed
catalyst bed at low or medium pressure and in the presence of hydrogen.

☐ "Ethylbenzene production" means the process of combining benzene and ethylene to form ethylbenzene.

☐ "FCC gasoline hydrotreating with minimum octane loss" means selective desulfurization of FCC gasoline cuts with minimum olefins saturation, over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen.

☐ "Flare gas recovery" means a refinery unit in which flare gas is captured and compressed for other uses. Usually recovered flare gas is treated and routed to the refinery fuel gas system. Depending upon the flare gas composition, recovered gas may have other uses. The equipment for this process includes, but is not limited to, the compressor and separator.

☐ "Flexicoker" means a refinery unit which conducts a proprietary process incorporating a fluid coker ~~and~~ where ~~the surplus~~ coke is gasified to produce a so-called "low BTU gas" which is used to supply the refinery heaters and surplus coke is drawn off as a product.~~.~~

☐ "Flue gas desulfurizing" means a process in which sulfur dioxide is removed from flue gases with contaminants. This often involves an alkaline sorbent which captures sulfur dioxide and transforms it into a solid product. Various methods exist with varying sulfur dioxide removal efficiencies. Flue gas desulfurizing systems can be of the regenerative type or the non-regenerative type. The processes and equipment for this process include, but are not limited to, the contactor, catalyst/reagent regeneration, scrubbing circulation and solids handling.

☐ "Fluid Catalytic Cracking" means cracking of a hydrocarbon stream typically consisting of ~~vacuum~~ gasoils and residual
feedstocks over a catalyst. The finely divided catalyst is circulated in a fluidized

state from the reactor where it becomes coated with coke to the regenerator where coke is burned off. The hot regenerated catalyst returning to the reactor supplies the heat for the endothermic cracking reaction and for most of the downstream fractionation of cracked products.

☐ "Fluid Coker" means a proprietary continuous process where the fluidized powder-like coke is transferred between the cracking reactor and the coke burning vessel and burned for process heat production. Surplus coke is drawn off and ~~disposed of~~ as a product.

~~**Language to Support Complexity Weighted Barrel (CWB)**~~

~~12~~

☐ "Fuel gas sales treating & compression" means treatment and compression of refinery fuel gas for sale to a third party.

Hydrogen Generation" means a unit producing hydrogen. Steam Methane Reforming, includes units producing hydrogen from steam reforming of natural gas or refinery gases. Steam Naphtha Reforming includes units producing hydrogen from steam reforming of naphtha. Partial Oxidation Units produce steam from partial oxidation of fuel oil. The primary product is hydrogen. Low btu gas or Carbon Dioxide are byproducts of these plants. The CWB factors for hydrogen purification units, such as Cryogenic Unit, Membrane Separation Unit, and Pressure Swing Adsorption (PSA) unit, as well as U71 (CO Shift & H2 Purification) and U72 (POX Syngas for H2 Generation), are allocated among Hydrogen Generation units.

☐ "Hydrodealkylation" means dealkylation of toluene and xylenes into benzene over a fixed catalyst bed and in the presence of hydrogen at low to moderate pressure.

☐ "Kerosene hydrotreater" means a refinery process unit which treats and upgrades kerosene and gasoil streams using "aromatic saturation of distillates," "distillate hydrotreating," "middle distillate dewaxing" or the "S-Zorb™ process for kerosene and gasoil" or "selective hydrotreating of distillates."

☐ "Lube catalytic dewaxing" means catalytic breakdown of long paraffinic chains in intermediate streams in the manufacture of lube oils.

☐ "Lube solvent dewaxing" means solvent removal of long paraffinic chains (wax) from intermediate streams in the manufacture of lube oils. Includes solvent regeneration. Different proprietary processes use different solvents, such as chlorocarbon, MEK/toluene, MEK/MIBK, or propane.

☐ "Lube solvent extraction" means solvent extraction of aromatic compounds from intermediate streams in the manufacture of base lube oils. This includes solvent regeneration. Different proprietary processes use different solvents, such as Furfural, NMP, phenol, or SO2.

☐ "Lube/Wax hydrofining" means hydrotreating of lube oil fractions and wax for quality improvement.

☐ "Lubricant hydrocracking" means hydrocracking of heavy feedstocks for the manufacture of lube oils.

☐ "Methanol synthesis" means recombination of CO2 and hydrogen for methanol synthesis. This factor is only applicable when a refinery produces hydrogen via partial oxidation.

☐ "Middle distillate dewaxing" means cracking of long paraffinic chains in gasoils to improve cold flow properties over a fixed catalyst bed at low or medium pressure and in the presence of hydrogen. This process includes the desulfurization step which should therefore not be accounted for separately.

☐ "Mild Residual FCC" means fluid catalytic cracking when the feed has a Conradson carbon level of 2.25% to 3.5% by weight.

☐ "Naphtha/Distillate Hydrocracker" means a refinery process unit which conducts cracking of a hydrocarbon stream typically consisting of distillates and gasoils ~~vacuum gasoils and cracked heavy distillates~~ over a fixed catalyst bed, at high pressure and in the presence of hydrogen. The process combines

~~**Language to Support Complexity Weighted Barrel (CWB)**~~

~~13~~

cracking and hydrogenation reactions. ~~Conversion of naphtha into C3-C4 hydrocarbons is included here.~~

☐ "

Naphtha Hydrotreater" means a refinery process unit which treats and upgrades a hydrocarbon stream typically consisting of naphtha/gasoline and lighter streams. It includes the following process units: Benzene Saturation, Desulfurization of C_4-C_5 Feeds, Conventional Naphtha Hydrotreating, Diolefin to Olefin Saturation of Gasoline, FCC Gasoline Hydrotreating with Minimum Octane Loss, Olefinic Alkylation of Thiophenic Sulfur, Selective Hydrotreating of Pyrolysis Gasoline/Naphtha Combined with Desulfurization, Pyrolysis Gasoline Desulfurization, Reactor for Selective Hydrotreating and S-Zorb™ Process.

~~Naphta hydrotreater" means a refinery process unit which treats and upgrades a hydrocarbon stream typically consisting of naphtha/gasoline and lighter streams using "benzene saturation," "desulfurization of C4–C6 feeds," "conventional naphtha hydrotreating," "diolefin to olefin saturation of gasoline," "FCC gasoline hydrotreating with minimum octane loss," "olefinic alkylation of thio sulfur," and/or "desulfurization of pyrolysis gasoline/naphtha," is a "reactor for selective hydrotreating" and may also use the "S-Zorb™ process for naphta/distillates."~~

☐ "Olefinic alkylation of thio sulfur" means a gasoline desulfurization process in which thiophenes and mercaptans are catalytically reacted with olefins to produce higher-boiling sulphur compounds removable by distillation. This does not involve hydrogen.

☐ "Other FCC" means early catalytic cracking processes on fixed catalyst beds, including Houdry catalytic cracking and Thermofor catalytic cracking.

☐ “Oxygenates” means ethers produced by reacting an alcohol with olefins.

☐ “Paraxylene production” means physical separation of paraxylene from mixed xylenes.

☐ “Propane/Propylene splitter (propylene production)” means a refinery unit that conducts separation of propylene from other mostly olefinic C3/C4 molecules generally produced in an FCC or coker. Its product is propylene and must be chemical or polymer grade. "Chemical" and "polymer" are two grades with different purities.

☐ “POX syngas for fuel” means production of synthesis gas by gasification (partial oxidation) of heavy residues. This includes syngas clean-up.

☐ “Reactor for selective hydrotreating” means a special configuration where a distillation/fractionation column contains a solid catalyst that converts diolefins in FCC gasoline to olefins or where the catalyst bed is in a preheat train reactor vessel in front of the column.

☐ “Reformer - including AROMAX” means a refinery unit which increases the octane rating of naphtha by dehydrogenation of naphthenic rings and paraffin isomerisation over a noble metal catalyst at low pressure and high temperature. The process also produces hydrogen. Different configurations of the process are possible.

☐ “Residual FCC” means fluid catalytic cracking when the feed has a Conradson carbon level of greater than or equal to 3.5% by weight.
~~Language to Support Complexity Weighted Barrel (CWB)~~
~~14~~

☐ “Residual hydrotreater” means a refinery unit which conducts desulfurization of residues over a fixed catalyst bed at high pressure and in the presence of hydrogen. It results in a limited degree of conversion of the residue feed into lighter products.

☐ “Residual Hydrocracker” means a refinery unit which conducts hydrocracking of residual feedstocks. Different proprietary processes involve continuous or semicontinuous catalyst replenishment. The residual hydrocracker unit must be designed to process feed containing ~~at least 50% mass of~~ vacuum ~~residue~~ residuum ~~(defined as boiling over 550°C)~~ for it to qualify as a residual hydrocracker for the purposes of complexity-weighted barrel throughputs.

☐ “S-Zorb™ process for kerosene and gasoil” means desulfurization of gasoil using a proprietory absorbtion process. This process does not involve hydrogen.

☐ “S-Zorb™ process for naphtha/distillates” means desulfurization of naphtha/gasoline streams using a proprietary fluid-bed hydrogenation adsorption process in the presence of hydrogen.

☐ "Selective hydrotreating of diolefins ~~distillates~~" means selective saturation of diolefins in
C4 streams for alkylation over a fixed catalyst bed, at moderate pressure and in the presence of hydrogen,
"Selective hydrotreating of distillates" means selective hydrotreating to produce a low contaminant distillate. ~~or hydrotreatment of distillates for conversion of diolefins to olefins.~~

☐ "Solvent deasphalter" means a refinery unit which utilizes a solvent, such as propane, butane or a heavier solvent, to remove asphaltines from a residual oil stream and produces asphalt and a deasphalted gas oil. ~~conducts separation of the lighter fraction of a vacuum or cracked residue by means of a solvent such as propane, butane or heavier.~~

☐ "Special Fractionation" means fractionation processes ~~excluding solvents, propylene and aromatics fractionation,~~ which are accomplished by a deethanizer, depropanizer, deisobutanizer, debutanizer, deisopentanizer, depentanizer, deisohexanizer, dehexanizer, deisoheptanizer, deheptanizer, naphtha splitter, alkylate splitter or reformate splitter. Production of solvents, propylene and aromatics are excluded from "Special Fractionation" but included elsewhere.

☐ "Standard FCC" means fluid catalytic cracking when the feed has a Conradson carbon level of less than 2.25% by weight.

☐ "~~Sulfur~~ Sulfur Recovery ~~(recovered)~~" means a process where hydrogen sulfide is ~~removed from the process and~~ converted to elemental sulfur. Typical units used in this process include: Sulfur Recovery Unit, Tail Gas Recovery Unit, and H2S Springer Unit. ~~sulfur produced by partial oxidation of hydrogen sulfide into elemental sulfur.~~

☐ "Sulfuric acid regeneration" means a catalytic process in which spent acid is regenerated to concentrated sulfuric acid. The equipment for this process includes, but is not limited to, the combustor, waste heat boiler, converter, absorber, SO3 recycle, gas cleaning including electrostatic precipitator and amine regenerator.

~~Language to Support Complexity Weighted Barrel (CWB)~~
~~15~~

☐ "Thermal Cracking" means thermal cracking of distillate feedstocks. A thermal cracking unit may include a vacuum flasher. Units that combine visbreaking and thermal cracking of distillate generate a contribution for both processes based on the residue and the distillate throughput respectively.

☐ "Toluene disproportionation/transalkylation means a fixed-bed catalytic process for the conversion of toluene to benzene and xylene in the presence of hydrogen.

☐ "Vacuum Distillation" means distillation of atmospheric residues under vacuum. ~~The process line-up must include a heater.~~ Some units may have more than one main distillation column.

☐ "Visbreaker" means a refinery unit which conducts mild thermal cracking of residual feedstocks to produce some distillates and reduce the viscosity of the cracked residue. It may include a vacuum flasher. Units that combine visbreaking and thermal cracking of distillate generate a contribution for both processes based on the residue and the distillate throughput respectively.

☐ "VGO Hydrotreater" means a refinery unit which conducts desulfurization of a hydrocarbon stream typically consisting of vacuum and cracked gasoils usually destined to be used as FCC feed, over a fixed catalyst bed at medium or high pressure and in the presence of hydrogen.

☐ "Wax deoiling" means solvent removal of lighter hydrocarbons from wax obtained from lube dewaxing. Different proprietary processes use different solvents, such as MEK/toluene, MEK/MIBK, or propane.

☐ "Xylene isomerization" means isomerization of mixed xylenes to paraxylene.

[OP 23.04 – WSPA]

D. Comment: Commenter supports the refined CWB definitions. Revisions were made in the 15-day revisions to address the recommendations provided. [T 10.03 – WSPA]

Response: (this response effective for comments D-2, A-D above) ARB staff thanks the stakeholder for the comments regarding use of the complexity weighted barrel instead of the carbon dioxide weighted tonne for determining the allocation of allowances under the Cap-and-Trade program. ARB staff worked closely with the refineries, WSPA and Solomon to address the reporting requirements of the complexity weighted barrel. As a result of these discussions, ARB staff has clarified complexity weighted barrel requirements in sections 95113 and 95131, and modified the definitions in section 95102 accordingly. ARB staff believes these changes address the commenter's concerns. The changes shift the reporting requirements from units of tons to barrels, which reduces the burden of reporting because the majority of a refinery's throughputs are in the liquid, not solid state.

D-3. 95113. WSPA Supports Use of CWB Instead of CWT

Comment: As stated previously, WSPA supports ARB's proposal to use CWB instead of CWT and recommends ARB make all necessary revisions and corrections as necessary to support CWB. [OP 08.12 – WSPA]

Response: ARB staff appreciates the commenter's support, and has proposed 15-day changes which remove all references to CWT and rely solely on CWB instead. These changes include definitional changes, table changes, and substantive reporting requirements found in sections 95102, 95113, and 95131 of the reporting regulation.

D-4. Support CWB, But Believes ARB "Inadvertently" Did Not Include CWB Factor for Hydrogen

Comment: WSPA supports the use of the CWB, but ARB "inadvertently" did not include a CWB factor for hydrogen. [T 10.01 – WSPA]

Response: ARB staff thanks WSPA for their support of moving from the CWT to the CWB factors. ARB staff is not including a hydrogen production throughput function or factor in the CWB function and factor table because the reporting requirements related to the allowance allocation for hydrogen production are included in section 95114 of the reporting regulation.

D-5. Concern About Double Counting for Refiners

Comment: Valero is concerned that the updated definition stating that refinery operators and refiners were two distinct entities will result in double reporting for some entities unless some clarifications are made.

Petroleum Refinery Operators vs. Refiners (pg. 52 of the Proposed Order)

Indirectly related to the reporting of transportation fuels is the language in section 95113, which in the Proposed Order, has this new sentence: "Petroleum refinery operators and refiners are considered separate reporting entities for the purposes of this article." While it appears that the purpose of this statement is to account for corporate structures so that an entity cannot avoid reporting due to definitional variance, this new sentence does imply that operators and refiners are mutually exclusive in all cases. The definition should clarify the need for itself, particularly with regard to the corporate function of the two types of entity. The new language should be struck or clarified to assure that an entity does not have to double report the same emissions.

[OP 13.03 – VC]

Response: ARB staff made the originally proposed amendment to section 95105(c) to ensure that verifiers give appropriate scrutiny to the supplier and refinery operations that would not otherwise occur if only a single emissions data report was submitted. This includes a requirement for separate sampling plans to address distinct risks in each emissions data report and to undertake separate site visits, if the data and key staff are located at separate facilities. ARB staff believes this requirement is important because refineries and fuel suppliers often represent particularly large, complex, and emissions-intensive reporting entities. ARB staff believes this requirement will not result in double counting and, if necessary, will clarify its intent in guidance. ARB, therefore, declines to make the requested change.

D-6. Disaggregation of Refinery and Fuel Supplier Data Reports

Comment: Kern Oil requests the removal of the new language in section 95113 requiring refinery operators to report GHG emissions under a separate ARB ID than the transportation fuel supplier emissions reported by the refiner. This provision does not improve accuracy of reported data for Kern Oil, and imposes additional costs and burdens associated with preparing and verifying a separate GHG report.

Separate Obligations for Entities with Facility Emissions and Fuel Supplier Emissions

As a small business and small California refinery, Kern is not supportive of proposed revisions to Section 95113 that would require the operator of a petroleum refinery to report and verify separately, and under two distinct ARB ID numbers, the facility emissions and the fuel supplier emissions. Similarly, Kern is not supportive of proposed revisions to Section 95105(c) that would require two separate GHG Monitoring Plans for a single entity that must report both facility emissions and fuel supplier emissions. Both of these proposed changes are burdensome and costly in requiring an entity to prepare two reports, obtain two verifications and maintain two GHG Monitoring Plans, none of which appear to provide commensurate additional value or significant improvements to meeting compliance obligations. Sufficient detail pertaining to both facility emissions and fuel supplier emissions compliance obligations can effectively be captured and maintained distinct in a single, combined GHG Monitoring Plan and within combined annual reports. Kern suggests that ARB maintain these referenced sections as they are currently written. Doing so will be consistent with existing regulatory language in section 95101(a)(2) that refers to *a single annual emissions report for an entity in one or more of the categories* in subsection (a)(1). Kern notes there exist proposed revisions to Section 95101(a)(2) within this 45-day amendment package, but Staff's proposed edits likewise maintain the approach that an entity prepare a single report even when obligated by more than one function.

[OP 35.01 – KOR]

Response: ARB staff made the originally proposed amendment to section 95105(c) to ensure that verifiers gave appropriate scrutiny to the supplier and refinery operations that would not otherwise occur if only a single emissions data report was submitted. This includes a requirement for separate sampling plans to address distinct risks in each emissions data report and to undertake separate site visits, if the data and key staff are located at separate facilities. ARB staff believes this requirement is important because refineries and fuel suppliers often represent particularly large, complex, and emissions-intensive reporting entities. ARB agrees with the commenter that reporting entities could incur some additional costs to compensate verifiers for additional time, but ARB staff believes this is mitigated where no additional site visits must be undertaken, as in the commenter's case. ARB, therefore, declines to make the requested change.

§95114 – Hydrogen Production

D-7. Reporting of Carbon and Hydrogen Content

Comment: 1. Air Products does not support adding a requirement for hydrogen producers to provide carbon and hydrogen content for all feedstocks. Such a requirement adds compliance costs with no material gain toward informing the overall state GHG emission inventory. [§95114(e)(1)] Air Products acknowledges that staff has reduced the sampling burden for other gaseous fuels from an initial proposal of daily to monthly. Nevertheless, adding this requirement will increase the cost of compliance for hydrogen production facilities in the following ways:

a. Facilities that made the irrevocable decision (under 40CFR98) to employ CO2 CEMS, consistent with 40CFR98.163(a), made such investments as a means to avoid the more significant costs associated with sampling, analyzing, and measuring the flow of multiple fuel and feedstock streams used to produce hydrogen at that facility. Both US EPA and the CA ARB have accepted CEMS emissions determinations for compliance reporting.

While the capital, operating, calibration and maintenance costs for proper operation of a CO2 CEMS is also significant, the “elegance” of a CEMS approach is that it does not require the multiple sampling, analysis flow measurement, and data handling tasks (and costs). Under the proposed §95114(e)(1)(A) revision, monthly analysis for carbon and hydrogen content would be required for all gaseous feedstocks, including natural gas. Typical natural gas supplier data, even when available monthly, does not provide hydrogen content values, necessitating sampling and analysis for even a stream that has negligible hydrogen content and variability from standard specification values. This requirement to sample and analyze gaseous feedstock streams adds compliance costs - sampling, shipping, contract lab analysis, and data management requires in excess of $500 per sample – so characterization according to §95114(e)(1)(A) standards results in an additional cost of $6,000 per year for each feedstock. Costs for installing and maintaining feedstock flow measurement devices (needed to calculate the carbon and hydrogen content of the feedstocks as a “weighted average”) further increase the capital, calibration and maintenance costs to satisfy the feedstock characterizations proposed under §95114(e)(1)(A).

The proposed amendment to the MRR will require facilities that have already committed to a CEMS approach to incur these large, redundant costs to characterize their feedstock streams. These added costs are particularly unwarranted because the information the ARB will garner from the characterization of feedstocks will not effectively inform either their statewide emission inventory or support their efforts to derive and administer allowance allocation benchmarks under the cap & trade program. Air Products engaged ARB staff in an attempt to determine how feedstock. characterization data will enhance the ARB’s understanding/quality of the components of AB-32, but cannot ascertain any such benefit. Suggestions that theoretical calculations from hydrogen production and feedstock data will be useful, ignore the realities of process variability, equilibrium limitations of the chemical reactions taking place, process-critical recycle streams employed, degradation of catalyst activity over time, equilibrium limitations of crude hydrogen purification and numerous other real-world process deviations from theoretical or stoichiometric calculations as to render such “academic” exercises useless.

b. For facilities that chose to comply with the MRR using the fuel and feedstock mass balance approach, §95114(e)(1) indicates only carbon content and molecular weight determinations are required, which is consistent with the data required to calculate the GHG emissions according to 40CFR98.163(b). Air Products recommends that ARB modify the language of §95114(e)(1)(A) to clearly articulate that the requirement to characterize feedstock hydrogen content does not extend to facilities that are not monitoring CO2 emissions with a CEMS. As written, it can be inferred that §95114(e)(1) applies to both CEMS and non-CEMS monitoring methods, and §95114(e)(2) is an "in addition to" rather than an "instead of" requirement.

Air Products strongly recommends eliminating any sampling and analysis requirements imposed on pipeline natural gas feedstocks, and further recommends eliminating or reducing the sampling and characterization requirements for other gaseous feedstocks, except as otherwise needed to calculate the facility's GHG emissions. [OP 07.01 – AP]

Response: ARB staff thanks the commenter for acknowledging that ARB staff has worked with Air Products staff to on this issue. The purpose of the proposed amendments is to support the statewide greenhouse inventory. As such, ARB staff have allowed for flexibility in reporting this information by allowing for the use of engineering estimates, which may include carbon and hydrogen compositional information from their natural gas supplier. For this reason, ARB staff believes the burden of this reporting requirement is minimal. ARB staff declines to make any regulatory edits to section 95114(e)(1)(A). The commenter is correct in asserting that section 95114(e)(1) applies to CEMS and non-CEMS reporting entities, while section 95114(e)(2) applies just to non-CEMS entities.

D-8. Carbon Content Reporting and Sampling

Comment: ARB is proposing revisions to Section 95114(e) (1) and (e) (2) that will require reporters to sample for carbon and hydrogen content for each feedstock for hydrogen production units. Furthermore, we noted that the sampling frequency for carbon content from refinery fuel gas differs in sections (e) (1) and (e) (2). Section 95114(e) (1) states monthly sampling for carbon content and hydrogen content from fuels such as refinery fuel gas is required. Section 95114(e) (2) states daily sampling for carbon content and molecular weight from fuels such as refinery fuel gas is required. WSPA does not believe that daily sampling for carbon content and molecular weight from fuels is necessary to develop representative values.

It is not clear to WSPA why ARB is requiring reporters to sample for the hydrogen content and how this data will be useful in better delineating process and combustion emissions. Most facilities already track process feed and combustion emissions separately so there should be no need for adding additional reporting obligations that are unnecessary. WSPA is concerned that complying with requirements that do not provide any clear reason or value may also have the unintended result of having to install additional metering or special instrumentation processes unnecessarily.

- Section 95114(j)

With respect to Section 95114(j): WSPA requests ARB provide more clarification in this section. For example, if hydrogen gas is sold then the "…annual masses of on-purpose hydrogen and by-product hydrogen produced must be reported (metric tons)". Currently, as written, it is difficult to determine if hydrogen gas is NOT sold, then are the on-purpose and by-product hydrogen produced required to be reported?

Recommendations:
WSPA recommends that ARB remove the requirement in (e) (1) for “hydrogen content” data and the sampling requirements for both (e) (1) and (e) (2) be done consistently on a monthly basis. WSPA also recommends clarifications to Section 95114(j) on hydrogen gas product data. [OP 08.13 – WSPA]

Response: See response to comment D-7 for information regarding the purpose of adding section 95114(e)(1). ARB staff does not propose to change the requirements in section 95114(e)(2) to monthly because reporting entities have already been monitoring at the daily level for carbon content for the past two years. ARB staff sees no reason to revert to lower standards. The requirements in section 95114(j) were added to ensure the Cap-and-Trade program has the information necessary for allocation of allowances in the hydrogen production sector. ARB staff believes the intent is clear; if hydrogen gas is not sold, then the on-purpose and by-product hydrogen produced do not need to be reported. ARB staff will continue to work with stakeholders to ensure they understand the reporting obligations, and may issue clarifying guidance, if necessary.

D-9. Waste Gas Emissions Reporting

Comment: Air Products’ hydrogen production facilities across the U.S. report emissions under 40CFR98 Subpart P. EPA’s Subpart P recognizes that flare GHG emissions are negligible for hydrogen plants. Under 40CFR98.30(b)(4), emissions from flares are exempt from reporting unless otherwise required by provisions of another applicable Subpart (in this case, Subpart P). Subpart P does not require reporting GHG emissions from flares.

Air Products does not understand the ARB’s rationale for imposing the additional administration, calculation, recordkeeping and reporting tasks (and costs) of such negligible emissions. The ARB proposal, in §95114(l), to apply the flare emission calculations methodologies of §95113(d) (Petroleum Refineries) is overly burdensome The §95113(d) requirements reference 40CFR98 Subpart Y methods – emission estimating methodologies and reporting requirements specifically tailored by US EPA to Petroleum Refining facilities in recognition that the facilities covered under that Subpart are likely to have flare emissions which are not de minimis… and thus appropriately should have a requirement for estimating and reporting. Applying these methods to the negligible emissions of hydrogen production units is disproportionate. This is further demonstrated by the fact that under the initial versions of California’s MRR, when flare emission reporting was imposed, our hydrogen plants could routinely demonstrate that the emissions satisfied the de minimis reporting threshold. Air Products recommends the requirements of §95114(g) and (l) be eliminated. [OP 07.02 – AP]

Response: ARB staff disagrees with the commenter and believes that the reporting of flare emissions is needed for consistency and for completeness of reporting. In a previous version of the reporting regulation flaring was included, but was inadvertently dropped during a subsequent rulemaking. ARB is restoring this reporting requirement to ensure complete and comparable reporting requirements for all hydrogen producers, whether they are merchant hydrogen plants or refinery hydrogen plants. If the emissions from these flaring sources are small, ARB staff recommends using the de minimis provisions as outlined in section 95103(i).

D-10. Clarify Determination of Integrated Refinery Operation

Comment: The new requirement proposed asks hydrogen plant operators to specify if the hydrogen plant in an integrated refinery operation. All off-site hydrogen plants in California are closely integrated with at least one refinery customer. ARB has not provided any definition of what constitutes an “integrated refinery operation” in order for hydrogen plant operators to make such a determination. [OP 07.03 – AP]

Response: The term “integrated with a refinery” was in a previous rulemaking and not noticed in this rulemaking. As such, the comment is outside the scope of this rulemaking process. However, the term “integrated with a refinery” is designed to specify the difference between hydrogen merchant plants and hydrogen plants co-located at a refinery (i.e, within the facility boundary of a refinery or contiguous to a refinery).

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

§95115 – Stationary Fuel Combustion Sources

E-1. Local Distribution Company Pass-Through Natural Gas

Comment:

SoCalGas and SDG&E believe regulatory clarification is needed to confirm that Local Distribution Companies (LDCs) will receive a written notification from ARB as to which LDC facilities will have the reporting obligation for an entity who “passed through” natural gas to a separate facility when the natural gas was originally delivered by the LDC.

[B 02.06 - SU]

Response: The reporting requirements for LDC's do not change due to the rule changes affecting "pass-through" facilities (i.e. facilities that re-deliver a portion of gas received from the LDC to another facility). The amendments will ensure that all "pass-through" situations are identified by ARB staff. In cases where these "pass-through" situations affect a LDC’s covered emissions calculation, staff will work with the LDC to ensure that the LDC understands how the calculation is implemented.

E-2. Support for Product Data Reporting Additions

Comment: Support for additional product data reporting requirements for food processors. [T 03.01 – CLFP]

Response: ARB staff appreciates the commenter's support.

§95116 – Stationary Fuel Combustion Sources

No comments were received on section 95116.

§95117 – Stationary Fuel Combustion Sources

No comments were received on section 95117.

§95118 – Stationary Fuel Combustion Sources

No comments were received on section 95118.

§95119 – Stationary Fuel Combustion Sources

E-3. Tissue Product Descriptions

Comment: It is unclear if kitchen towels, facial tissue, and toilet paper are considered distinct tissue types for the purposes of reporting water absorption capacity. Clarification is requested. Also, P&G request that only a single composite water absorption value be reported which combines all products, to avoid divulging competitive data on the relative amount of each tissue type produced. [OP 17.01 – PG]

Response: Based on stakeholder input, staff modified the regulation in 15-day changes to clarify that water absorption capacity is to be reported in aggregate, and not for individual tissue products.

E-4. Tissue Water Absorption Capacity

Comment: The regulation does not specify a sampling frequency for determining water absorption capacity. P&G suggests that entities should be able to utilize the ARB specified method to determine the absorptive capacity of products using an annual weighted average, or, at the facility's option, conduct annual testing using the proposed test method. Testing should be performed on each tissue type, focusing on the predominant tissue product for each tissue type. Records for the tissue product selected, supporting information, test method and results would be maintained by the site and be verified. [OP 17.02 – PG]

Response: Based on stakeholder input, staff clarified the regulation in 15-day changes to specify that sampling is to be performed "at least annually."

E-5. Submission of Water Absorption Protocols

Comment: Provide an option to submit water absorption protocols to ARB prior to conducting tests. The protocol could describe the specific product in each tissue product type to be tested with the rationale for that selection, the number of samples to be tested, and any other important information to assure that sampling and testing is performed accurately and is representative of production. [OP 17.03 – PG]

Response: Staff reviewed this suggestion and declined to make a revision. In addition to the additional workload for staff and reporters, the methods required for performing the sampling are already explicitly defined in the regulation, and the clarifications added in the original proposed amendments regarding aggregation and sampling frequency make this change unnecessary.

§95120 – Stationary Fuel Combustion Sources

No comments were received on section 95120.

F. Subarticle 2. Fuel and Carbon Dioxide Suppliers and Lead Production (§95121 – §95124)

§95121 – Suppliers of Transportation Fuels

No comments were received on section 95121.

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

F-1. Reporting of ARB ID Numbers by Natural Gas Suppliers

Comment: Natural gas suppliers should not be required to report ARB ID numbers because they will not have access to the ARB IDs and requirements to match external facility identifiers to individual meters would prove unduly burdensome. PG&E recommends amending section 95122(d)(2)(E) as follows:

(E) ~~For each customer,~~ In lieu of reporting the information specified in 40 CFR §98.406(b)(7), local distribution companies including intrastate pipelines ~~that report under 40 CFR §98.406(b)(7)~~ must report the annual volumes in Mscf, annual energy in MMBtu, and customer information required in 40 CFR §98.406(b)(12)~~**, and ARB ID number if available**~~ for all end-users registering supply equal to or greater than 188,500 MMBtu during the calendar year.
[OP 09.11 – PG&E]

Response: ARB staff recognizes that suppliers may not have the ability to map customer names and addresses to ARB ID numbers for some facilities; therefore the amendments to section 95122(d)(2)(E) include the qualifier "if available" when requiring that ARB ID numbers be reported. ARB believes this language covers the commenter’s concern, and declines to make the requested changes.

F-2. Object to Duplicate Reporting of Pass-Through Natural Gas

Comment:

A. SMUD’s Previous Comments on the Mandatory Reporting Regulation Found Duplicate and Unnecessary Requirements. On July 10, 2013, SMUD commented on the issue of duplicate reporting under the MRR. SMUD explained at that time that it owns and operates roughly 76 miles of local gas pipeline that supplies natural gas to four SMUD power plants (“SMUD Local Pipeline System”). These power plants are covered Electricity Generating Units (“EGUs”) subject to MRR reporting and Cap-and-Trade compliance obligations. SMUD reports emissions on the EGUs’ behalves and likewise receives a direct allocation of GHG allowances on their behalves. SMUD is not a gas fuel supplier to any other industrial facilities or covered entities under the Cap-and Trade Program. However, because the four power plants are “owned” by joint powers authorities (“JPAs”), of which SMUD is the controlling party, and “buy” gas from SMUD, the JPAs meet the ARB’s literal definition of “end user” under the MRR. Accordingly, SMUD is technically a “publicly-owned natural gas utility” and “LDC” under the MRR, and instruments for those supplies. Given that SMUD makes all of its deliveries on a pass-through basis to its EGUs, and that deliveries to these end users are subtracted before calculating any compliance obligation, SMUD should have no separate gas LDC compliance obligation under the AB 32 Cap-and-Trade program. Indeed, during a conference call with ARB on September 26, 2013, SMUD was assured by ARB staff that this is the case for 2012 emissions. However, SMUD remains concerned that different reporting methods for SMUD’s EGUs and the SMUD Local Pipeline System could result in a variance in reported emissions on paper that do not exist in reality. The resulting discrepancy could lead to overstatement of a compliance obligation for the pipeline. For example, SMUD reports emissions from its Consumnes Power Plant (CPP) EGU pursuant to Subpart D of 40 CFR Part 98. To calculate GHG emissions from this facility, SMUD measures the volume of gas flowing into CPP's electric generating system (in MMscf), calculates the fuel heat input (in MMBtu), applies the GHG emission factor, and, where applicable, the global warming potential. Digester gas, which is supplied to CPP from the Sacramento Regional Wastewater Treatment Plant (SRWTP), and biomethane from out-of-state sources are used to supplement the natural gas fuel. Emissions from the biogas sources are deducted from CPP's total emissions. The result is that total covered emissions include only emissions from all natural gas supplied to the plant expressed in carbon dioxide equivalent, exclusive of any emissions from biogas. By contrast, SMUD reports fuel use for the Local Pipeline System in accordance with Subpart NN of 40 CFR Part 98. Under this regulation, SMUD receives a single heat energy value for the gas delivered at the pipeline from PG&E, as metered in dekatherms at the Winters Interconnection, which is then theoretically allocated to its power plants per fuel volume ratio. The fuel volumetric and heat input values for the pipeline versus the values for the four plants will not match due to slight differences between meters (SMUD's multiple plant meters and one PG&E revenue meter), and potentially in how the fuel is allocated among the plants. More significantly, reporting under Subpart NN does not account for the different compliance obligation of biomass-derived fuel, which will cause a discrepancy between the two results. SMUD believes that these differences in methodologies led to an additional 81,000 metric tons CO2e reported from the SMUD Local Pipeline System in 2012 over the aggregate of emissions from the four power plants. In previous comments, SMUD has objected that duplicate reporting of pass-through natural gas to its EGUs is overly burdensome and causes unnecessary expense in terms of staff time and verification costs. This is still true. However, the bigger problem is the potential for a compliance obligation on the SMUD Local Pipeline System resulting from the dissimilar reporting methodologies between the pipeline and EGUs. To date, these differences are relatively small and explainable. However, confusion could evolve over time. [OP 19.01 – SMUD]

B. SMUD recommends that language be added to deal with their special situation as a natural gas pipeline delivering only to their own power plants. Recommends a blanket 'exemption' from compliance obligation for gas pipeline. [T 14.01 – SMUD]

Response: (This response applies to F-2, A-B, above)

ARB understands that SMUD is in a unique situation in that its gas pipeline delivers fuel only to SMUD operated power plants, all of which separately report to ARB and are covered entities under the Cap-and-Trade program. However, an exception to natural gas supplier reporting requirements cannot be made for SMUD because ARB relies on the data reported by SMUD to identify volumes of gas received from the upstream LDC, and follow the natural gas to the end-users. This information is vital to ensuring that covered emissions calculations for natural gas suppliers are quantified accurately and that natural gas is not being delivered to non-covered entities without being reported. Per the reporting requirements in section 95122 for publicly owned natural gas utilities, it is very unlikely that differences in metered delivery data to SMUD's power plants would be materially different from the gas received from the upstream LDC. Therefore, ARB staff believes that SMUD will not have a covered emissions total anywhere close to the 25,000 MT CO_2e threshold that would trigger a duplicative compliance obligation for the SMUD natural gas supplier reporting entity. ARB staff is unaware of any situation where SMUD would end up with a duplicative compliance obligation. Therefore, ARB staff declines to make the changes suggested by SMUD. ARB staff notes that the remainder of SMUD’s comment letter OP19 concerned suggested changes to the Cap-and-Trade Regulation. As that is a separate rulemaking, ARB staff is not responding to that portion of the comment letter in this FSOR.

§95123 – Suppliers of Carbon Dioxide

No comments were received on section 95123.

§95124 – Lead Production

No comments were received on section 95124.

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

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

No comments were received on section 95129.

H. Subarticle 4. Verification and Verifier Requirements

(§95130 – §95133)

§95130 – Requirements for Verification of Emissions Data Reports

H-1. Conflict of Interest

Comment: WSPA recommends deletion of proposed language revisions in section 95130(a)(2) where ARB proposes to revise section 95130(a)(2) by adding to the list of verifications other program certifications or audits that include third party certification of environmental management systems to ISO 14001and third party certification of energy management systems to the ISO 50001 standard. Based on ARB's proposal, these previous certifications would also count toward a facility's consecutive 6-year limitation for using the same verifier. WSPA believes the level of scope and thorough review taken to perform AB32 third-party verifications is significantly different and more stringent from those that were conducted in the above mentioned audits. Because ARB would not consider any of these audits as an equal substitute to full-filling AB32 verification requirements going forward, it seems unfair for facilities to have to now count them if performed in the past. Many of these listed certifications were voluntarily performed in good faith to evaluate adherence with GHG requirements at the time, and reporters should not be penalized by having these certifications count toward their 6-year verifier limitation.

Recommendation: Delete proposed language revisions in Section 95130(a)(2).
[OP 08.05 - WSPA]

Response: ARB shares the commenter's commitment to ensuring the program is free from perceived or real conflict of interest, and encourages reporting entities to pursue other, voluntary verifications that they find beneficial to their operations in addition to following the requirements in the reporting regulation. The intention of the proposed change is to clarify those types of activities that verification bodies can perform on behalf of reporting entity that do not constitute a high conflict of interest, but which are included in the six consecutive year limitations for professional relationships among verification bodies and reporting entities. The original intention of this section, which is to mitigate the risk of a COI developing over time due to limiting the length of professional relationship between verification bodies and reporting entities, is unchanged. As previously written, those services described in the proposed language could have been considered a source of high conflict of interest, which was inconsistent with the intent of this section. The proposed language specifically notes that the activities are only considered in the six consecutive year limitation if they "include the scope of activities or operations under the ARB identified number for the emissions data report," which should reduce concerns that the proposed language applies COI requirements retroactively. As such, ARB declines to make the requested change, but will work with reporters and verifiers on an individual basis to determine the potential for COI and whether any mitigation procedures would be warranted.

§95131 – Requirements for Verification Services

H-2. Emissions Data Report Modifications

Comment: ARB proposes revisions to Section 95131(b) (9) that will require reporters to fix all correctable errors that affect covered emissions, non-covered emissions or covered product data. While WSPA members make every effort to ensure compliance with the accuracy requirements of the reporting regulation it is unreasonable to require all errors be corrected especially if the differences are of such small magnitude that they are insignificant and below the ± 5% accuracy level specified in the regulation. WSPA recommends ARB revise the following section to allow reporters flexibility to work with the verification team in determining what correctable errors actually need to be corrected. Additionally, WSPA believes correctable errors that are within ± 5% should not be considered a non-conformance.

Recommendation:
To incorporate the improvements noted above we recommend the following revisions (red font) to Section 95131(b) (9):

> "**The verification shall use professional judgment in the determination of correctable errors as defined in section 95102(a), including whether differences are not errors but result from truncation of rounding or averaging, or errors that are of such small magnitude they are determined to be insignificant.**

[OP 08.14 – WSPA]

Response: The purpose of the additions to section 95131(b)(9) was to ensure there were some defined limits on what ARB staff considers a correctable error. However, the language recommended by the commenter relies on the judgment of the verifier and may result in uncorrected errors that are large in magnitude. At this time, ARB staff is not considering a threshold of insignificance for a correctable error. ARB staff is committed to providing consistent information on the intent of this section to each verifier and if needed, ARB staff will publish guidance to explain the acceptable circumstances under which certain errors or identified differences do not require additional investigation for the purpose of determining conformance with the reporting regulation.

H-3. Correctable Errors

Comment: Provide an accuracy band that can be applied when evaluating "correctable errors" to include truncation, rounding, or other non-substantive differences.

B. Section 95131. ARB Should Allow Reasonable Emissions Data Report Modifications

PG&E appreciates staff's amendments to Section 95131(b)(9). However, we remain concerned that verifiers are still allowed too much discretion in the regard and that the regulation does not include an acceptable accuracy band. PG&E recommends the following changes:

> Section 95131(b)(9) Emissions Data Report Modifications. ~~As a result of data checks by the verification team and prior to completion of a verification statement(s)~~ **Provided the reporting entity receives notice from the verification team at least 10 days prior to the verification deadline,** the reporting entity must **make a reasonable effort to** fix all correctable errors that ~~**affect**~~ **result in a greater than one percent change in reported** ~~make any possible improvements or corrections to~~ covered emissions, non-covered emissions, or covered product data in the submitted emissions data report, and submit a revised emissions data report to ARB. Failure to do so will result in an adverse verification statement. Failure to **make a reasonable effort to** fix correctable errors that do not affect covered emissions, non-covered emissions, or covered product data ~~**represents a non-conformance with this article but**~~ does not, absent other errors, result in an adverse verification statement.

In instances where a facility is owned or operated by the electricity provider and/or natural gas provider, the proposed requirements included in Section 95131(b)(8)(F)(1) may prove difficult to meet due to the non-standard bills that are created. Therefore, PG&E recommends the following change to the proposed language:

> 1. For facilities that combust natural gas, natural gas provider, account identification number, **where available**, and annual MMBtu of natural gas delivered, reported pursuant to section 95115(k);

In addition, to ensure that the definition of "correctable errors" is sufficiently broad to address any error resulting from the use of reasonable calculation methods, PG&E recommends the following clarifying change to Section 95102:

> (107) "Correctable errors" means errors identified by the verification team that affect covered data, non-covered emissions data, or covered product data in the submitted emissions data report that result from a non-conformance with this article. Differences that, in the professional judgment of the verification team, are the result of differing but reasonable methods **including** ~~of~~ truncation or rounding or averaging, where a specific procedure is not prescribed by this article, are not considered errors and therefore do not require correction.

[OP 09.02 – PG&E]

Response: See response to comment H-2 regarding correctable errors. Additionally, ARB staff declines to make the change regarding the notification time for correctable errors. It is the responsibility of the reporting entity to ensure the data is reported correctly and accurately and that they respond to the verifier in a timely fashion. As they have done in the past, ARB staff is committed to providing assistance to the reporting entity and verification team to ensure any interpretational issues regarding the regulation are consistent and clear.

ARB staff declines to make the edit to section 95131(b)(8)(F)(1) because staff believes the language provided by the commenter is already implied in the requirement. If a reporting entity does not fill in the blank for the account number, the verifier will need to check for conformance that there was no valid account number.

H-4. Correctable Errors

Comment:

Requirements for Verification Services - §95131

SoCalGas and SDG&E have concerns that verifiers are afforded too much power to dictate what actions must be taken regarding fixing all correctable errors, 95131(b)(9). One of our verifier's insisted that staff correct every single error including one as small as resulting in a change of approximately one metric ton, which constituted a very small fraction of a percent of the total reported emissions. Staff was also directed to correct an emission factor that was not used for reporting purposes. Hours were spent on this exercise because no one wants to risk any type of negative reaction from a verifier who wields the power of a positive verification statement. We request that language be modified in 95131(b)(9) as suggested below red highlight and strikeout:

> *Section 95131(b)(9) Emissions Data Report Modifications. As a result of data checks by the verification team and prior to completion of a verification statement(s), giving the covered entity at least two weeks' notice prior to the verification deadline, the reporting entity ~~must~~ shall attempt to fix all correctable errors that result ~~affect~~ in a one percent or greater change in covered emissions, non-covered emissions, or covered product data in the submitted emissions data report. The covered entity shall~~, and~~ submit a revised emissions data report to ARB. Failure to do so will result in an adverse verification statement. Failure to make a reasonable effort to fix correctable errors that do not affect covered emissions, non-covered emissions, or covered product data ~~represents a non-conformance with this article but~~ does not, absent other errors, result in an adverse verification statement. The reporting entity shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the reporting entity for ten years pursuant to section 95105.*
>
> *The verification team shall use judicious professional judgment in the determination of correctable errors as defined in section 95102(a), including whether differences are not errors but result from truncation or rounding or averaging.*
>
> *The verification team must document the source of any difference identified, including their professional judgment as to whether the difference results in a correctable error.*

Section 95131(e) makes identification of an error a trigger for re-verification within 90 days by a different verification body. SoCal Gas and SDG&E appreciate the added language that provides ARB the ability to not require a full set aside of emissions for minor errors. We would additionally request the ability to appeal an ARB audit finding that a verification statement failed. To minimize ARB workload impact, these appeals could be handled through the regional district hearing boards. We therefore propose the following additional language modification to Section 95131(e):

> *Section 95131(e) If the Executive Officer finds a high level of conflict of interest existed between a verification body and a reporting entity, an error is identified, or an emissions data report that received a positive or qualified positive verification statement fails an ARB audit, the Executive Officer may set aside the positive or qualified positive verification statement issued by the verification body, and require the reporting entity to have the emissions data report re-verified by a different verification body within 90 days. This paragraph applies to verification statements for emissions and product data. In instances where an error to an emissions data report is identified and determined by ARB to not affect the emissions or covered product data, the change*
>
> 4
>
> *may be made without a set aside of the positive or qualified positive verification statement. A reporting entity may appeal an ARB audit finding that a verification statement failed through a regional district hearing board. The appeal petition must be filed within 30 days of the negative ARB audit, with a hearing scheduled 30 days after the petition is filed. While the appeal is pending, the 90 day clock to obtain a new verification is to be stayed pending the outcome of the appeal.*

[B 02.05 – SU]

Response: See response to comment H-3 regarding the correctable errors portion of the comment. Regarding the request for changes to include a petition process and a regional district hearing board, ARB notes that the reporting regulation is implemented and administered by ARB, not the air districts. Moreover, in cases where ARB staff finds an error in the reported emissions or product data, staff will work the reporting entity to ensure they understand the error before issuing the set aside. As such, a petition process and hearing board are not necessary. Furthermore, a lengthy data review/hearing process would impact the integrity of the Cap-and-Trade Program, where it is essential for timely emissions data to inform on market rules, such as holding limits, that protect against market manipulation. Based on the above explanation, ARB declines to make the requested change.

H-5. Emissions Data Report Modifications

Comment: ARB proposes revisions to Section 95131(b) (9) that will require reporting entities to fix all correctable errors that affect covered emissions, non-covered emissions or covered product data. CLFP members make every effort to ensure the accuracy of their compliance reporting per the requirements of the regulation. However, it is unreasonable to require all errors be corrected especially if the differences are of such small magnitude that they are insignificant and/or below the ±5% accuracy level specified in the regulation. CLFP recommends that ARB revise the regulation to allow reporting facilities the flexibility to work with the verification team in determining what correctable errors actually need to be corrected and that correctable errors that are within ± 5% should not be considered a non-conformance.

CLFP also urges ARB to adopt the following revisions to Section 95131(b) (9):

“The verification team shall use professional judgment in the determination of correctable errors as defined in section 95102(a), including whether differences are not errors but result from truncation of rounding or averaging, or errors that are of such small magnitude they are determined to be insignificant.". [OP 36.03 – CLFP]

Response: Please see response to comment H-2.

H-6. Set-Aside of Data Reports With Errors

Comment: ARB proposes revising Section 95131(e) by including that if “an error is identified” the Executive Officer (EO) may set the positive or qualified verification aside and require the reporter to re-verify the MRR report by a different verification body. Additionally, ARB also added the following language:

“In instances where an error to an emissions data report is identified and determined by ARB to not affect the emissions or covered product data, the change may be made without a set aside of the positive or qualified positive verification statement”.

WSPA understands ARB’s desire to ensure the submittal of accurate emissions and covered product data; however, it is important to note that the MRR specifies reporters must ensure emission and covered product data meet a standard level of accuracy of at least 95%. While ARB states if an error is determined to not affect the emissions or covered product data the facility will not be required to set aside the positive or qualified verification, it does not specifically consider the fact that errors could be within + 5% and therefore meet the accuracy standards specified in the regulation.

WSPA recommends ARB revise their proposed revisions by clarifying that errors that do not affect the 95% level of accuracy for emissions and covered product data will not result in ARB setting aside a positive or qualified positive verification.

Recommendation:
ARB should revise the proposed language as follows (see red font):

“In instances where an error to an emissions data report is identified and determined by ARB to not affect the 95% accuracy standard for emissions or covered product data, the change may be made without a set aside of the positive or qualified positive verification statement.”

[OP 08.06 – WSPA]

Response: The proposed language seeks to clarify the circumstances under which ARB may make adjustments to the emissions data report versus those where the emissions data report would need to be set aside and re-verified. ARB staff believes that, in order to support a robust Cap-and-Trade program, any adjustment to emissions or covered product data need to be done through a process of re-verification. ARB staff believes that making this determination on a case-by-case basis, based on each case's unique circumstances, is preferable to the approach outlined in the comment, and declines to make the requested changes.

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

No comments received in this section.

§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. Emulsion Definition

Comment: ARB has added the definition of "emulsion" to 95102(a)(149) as follows:

(149) "Emulsion" means a mixture of water, crude oil, associated gas, and other components from the oil extraction process that is transferred from an existing platform that is permanently affixed to the ocean floor and that is located outside the distance specified in the "offshore" definition of this article, to an onshore petroleum and natural gas production facility. For purposes Appendix B, emulsion means a mixture of crude oil, condensate, or produced water in any proportion.

The term emulsion can be used in several different contexts and processes within the oil and gas industry. By this definition the ARB is clarifying, for the purposes of the MRR, that requirements related to the term "emulsion" apply exclusively to fluids produced offshore.

ARB has also added the following phrase to the definition of "Onshore Petroleum and Natural Gas Production" industry segment in 95150(a)(2).

“Crude oil and associated gas that is piped to an onshore production facility as an emulsion as defined in section 95102(a) must follow the requirements of section 95156(a)(7)-(10) and meet the metering requirements of section 95103(k) by measuring the emulsion before the first separation tank at the onshore production facility and not at the platform.”

The current proposed definition of onshore production segment may cause confusion in the reporting requirements of 95156(a)(7)-(10).

Recommendation:
WSPA recommends that the phrase added to 95150(a)(2) be clarified to reflect the specific definition of “emulsion” in the context stated in Section 95102(a)(149) as follows:

> “Crude oil and associated gas that is piped to an onshore production facility as an emulsion from an offshore platform as defined in section 95102(a) must follow the requirements of section 95156(a)(7)-(10) and meet the metering requirements of section 95103(k) by measuring the emulsion before the first separation tank at the onshore production facility and not at the offshore platform.”

Also, revise the definition in 95150(a)(2) to include “or to which emulsion is transferred” to make it consistent with the proposed amended definitions of “facility” and “onshore petroleum and natural gas production facility” found elsewhere in the MRR and Cap and Trade Regulations

Finally, ARB should make definitions in the Cap and Trade and MRR regulations consistent. For example: The definitions of “Onshore Petroleum and Natural Gas Facility” are not consistent between the Mandatory Reporting Regulation and Cap and Trade Regulation:

a) Cap and Trade definition of "facility" (proposed 134(C), p. 19-20): "all petroleum and natural gas equipment on a well-pad, or associated with a well pad or to which emulsion is transferred"

b) MRR definition of "onshore petroleum and natural gas production facility" (proposed 326, p. 15): "all petroleum and natural gas equipment on a well-pad, or associated with a well pad or to which emulsion is transferred"

c) MRR definition of "facility" (proposed 171, p. 11): "all petroleum and natural gas equipment on a well-pad, associated with a well pad or to which emulsion is transferred"

The last of the three definitions (proposed 171, p. 11) which uses “or” only once appears to be the clearest.

Recommendation:
Revise the Cap and Trade definition of "facility" (proposed 134(C), p. 19-20) and the

MRR definition of "onshore petroleum and natural gas production facility" (proposed 326, p. 15) to be consistent with the MRR definition of "facility" (proposed 171, p. 11).

The revised definitions of "facility" (proposed 171, p. 11) and "onshore petroleum and natural gas production facility" (proposed 326, p. 15) strike the word "hydrocarbon" from the phrase "single hydrocarbon basin." However, the same change has not been made to the relevant definition of "facility" in the Cap and Trade regulation (proposed 134(C), p. 19-20).

Recommendation***:***
Revise the Cap and Trade definition of "facility" (proposed 134(C), p. 19-20) to be consistent with the MRR definitions. [OP 08.15 – WSPA]

Response: At this time, ARB staff declines to make the proposed change to the definition of “onshore petroleum and natural gas production” in section 95150(a)(2). The commenter’s proposed change would add language that staff believes is already contained in the definition of “emulsion” in section 95102(a). Therefore, adding in the extra language does not change the overall meaning of the existing proposed amendment. Staff also notes that adding the text, “or to which an emulsion is transferred” to section 95150(a)(2) is not necessary because it is still clear from the current proposed language that emulsions need to be reported according to the requirements of an onshore petroleum and natural gas production facility.

The comments that relate to the proposed amendments from the separate Cap-and-Trade Program rulemaking proceedings are outside the scope of the amendments included in the MRR rulemaking proceeding. However, ARB staff will work to ensure, to the extent feasible, that definitions are consistent between the MRR and Cap-and-Trade regulation.

§95151 – Reporting Threshold

No comments were received on section 95151.

§95152 – Greenhouse Gases to Report

I-2. Add Source Category for Pipeline Main Equipment Leaks

Comment: Add the source category "pipeline main equipment leaks" without section 95152(i) of the regulation so it is consistent with 40 CFR 98.232(i)(5).

J. Section 95152. Pipeline Main Emissions Should Be Listed as a Source Category for Distribution Systems

A comparison with EPA's list of GHG reporting requirements for distribution systems (40 CFR 98.232(i)(5)) indicates that Section 95152(i) of the MRR does not list pipeline main emissions as one of the required source categories. Therefore, PG&E recommends the following modification to the list that appears in Section 95152 to ensure consistency between the two regulations:

(i) For natural gas distribution, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

…

(5) Equipment and pipeline blowdowns;

(6) Pipeline main equipment leaks

(7) Service line equipment leaks;

(8) Report under section 95150 of this article the emissions of CO2, CH4, and N2O emissions from stationary combustion sources following the methods in 95153(y); and

(9) Flare stack emissions.

[OP 09.10 – PG&E]

Response: ARB staff agrees with the proposed change from the commenter. In order to maintain consistency with the U.S. EPA Greenhouse Gas Reporting Rule, the reporting requirement for pipeline main equipment leaks was added to section 95152(i)(9) of the MRR. An additional reference to section 95152(i)(9) was added to section 95153(p). These changes are reflected in the proposed 15-day modifications.

§95153 – Calculating GHG Emissions

I-3. Crude Oil Well Completion and Workover GHG emission reporting requirement.

Comment: ARB proposed revisions to Section 95153(f) to require reporters to measure and report vented GHG emissions associated with crude oil well completion and well workover work. Applying this new requirement to “crude oil wells” is inappropriate because the amount of emissions, if any, is small and is primarily fugitive in nature during oil well completion and workover work.

USEPA's April 12, 2010 Subpart W Background Technical Support Document (TSD) references previous emission studies for both the natural gas industry segment and the petroleum industry segment. Based on these studies and other relevant information, the

USEPA concluded that measurements were required to quantify emissions from gas well workovers and completions, but that the emissions from oil wells were so small and were sufficiently known as to not require inclusion in Subpart W reporting.

Emissions from oil wells are very small for a number of reasons. One significant factor is the comparatively low pressure at which the oil exists in the reservoir. It is this low pressure that usually requires pumps to bring the oil to the surface while gas wells exist at pressures high enough to allow the gas to flow freely to the top of the well. In addition, operators are required to follow regulatory standards set by the Division of Oil, Gas & Geothermal Resources (DOGGR) to ensure the well is fully under control prior to conducting any well completion or workover work. These standards include a variety of well control equipment and procedures that are based on the characteristics of the well and require operators to ensure there is no fluid or gas emission flowback during completion and well workover work.

WSPA conducted a preliminary member survey of the cost to install and operate a measurement system on individual well completion and workover equipment described in the proposed section. Using recently published USEPA emission factors for oil and gas operations (see below), the estimated cost of metering (not controlling) emissions was in excess of $100,000 per ton of CO2e emissions.

The above costs are based on the assumption metering equipment exists to capture GHG emissions during completion and well workover work. It is important to note that because any emissions during oil well completion and workover work are most likely to be fugitive in nature, it is not technologically feasible to utilize any of the proposed calculation methodologies stated in 95153(f)(1) and (2). Therefore, the costs are simply estimates to illustrate the expense of the proposed requirement compared with the emissions that might be quantified.

Alternatively, because there exists no technologically feasible way to perform measurements to quantify any GHG emissions, ARB may consider utilizing recently published U.S. EPA emission factors for quantifying GHG emissions associated with Oil & Gas operations (USEPA Technical Support Document for NSPS OOOO and table below).

Recommendation:
Delete the reference: “Crude oil and” from section 95913(f). If ARB remains concerned about emissions from crude oil well workover and completion activities, then the agency should work with stakeholders to develop an alternative emission factor method before proceeding further.

Table 4-2. Uncontrolled Emissions Estimates from Oil and Natural Gas Well Completions and Recompletions

Well Completion Category	Emissions (Mcf/event)	Emissions (tons/event)		
	Methane	Methane[a]	VOC[b]	HAP[c]
Natural Gas Well Completion without Hydraulic Fracturing	38.6	0.8038	0.12	0.009
Natural Gas Well Completion with Hydraulic Fracturing	7,623	158.55	23.13	1.68
Oil Well Completions	0.34	0.0076	0.00071	0.0000006
Natural Gas Well Recompletion without Hydraulic Fracturing	2.59	0.0538	0.0079	0.0006
Natural Gas Well Recompletion with Hydraulic Fracturing	7,623	158.55	23.13	1.68
Oil Well Recompletions	0.057	0.00126	0.001	0.0000001

Minor discrepancies may exist due to rounding.

a. Reference 4, Appendix B., pgs 84-89. The conversion used to convert methane from volume to weight is 0.0208 tons methane is equal to 1 Mcf of methane. It is assumed methane comprises 83.081 percent by volume of natural gas from gas wells and 46.732 percent by volume of methane from oil wells.

b. Assumes 0.1459 lb VOC /lb methane for natural gas wells and 0.8374 lb VOC/lb methane for oil wells.

c. Assumes 0.0106 lb HAP/lb methane for natural gas wells and 0.0001 lb HAP/lb methane for oil wells.

[OP 08.17 – WSPA]

Response: After reviewing stakeholder comments, ARB staff agrees with the commenter regarding the high cost for adding a measurement system for crude oil well completions and workovers. The proposed 15-day modifications include the removal of "crude oil" requirements from section 95153(f) as requested by the commenter. Because of the importance of this emission source, ARB staff worked with the stakeholders to determine the best method for collecting the emissions data from crude oil well workovers and completions, and 15-day language was added to section 95157(c)(6) to achieve the same reporting outcome as the originally proposed language at a lower cost.

I-4. Include Engineering Estimate for Vented Emissions

Comment: ARB Should Include A Reasonable Engineering Estimation For Calculating Vented Emissions For Natural Gas Distribution Systems

Section 95152(i)(5) requires reporting entities to measure and report emissions from equipment and pipeline blowdowns in natural gas distribution systems. The current methodology provided in Section 95153(g) will require a significant commitment of time and resources without commensurate benefits in terms of reporting accuracy. This will be particularly true in the case of calculating the unique piping volume in a natural distribution system.

Despite allowing the use of engineering estimates to calculate unique piping volumes, ARB still requires reporting entities to maintain a detailed record of all natural gas distribution system blowdowns as stated in item 4 of the Petroleum and Natural Gas

Systems (Subarticle 5): Emissions Reporting Guidance. As a result, reporting entities will be required to track the unique piping volumes to match the recorded number of distribution system blowdowns. Developing a system to track the unique piping volumes and maintain a record of the associated number of blowdowns for natural gas distribution assets is impractical and unduly burdensome given the 42,000 miles of distribution main and 2,800 regulator stations PG&E operates. Furthermore, when testing or replacing these facilities, PG&E minimizes the length of pipe to be evacuated (typically a city block or less) to reduce the impacts to customers. Consequently, the volume of gas released during a distribution blowdown is small as compared to the distribution system fugitive emissions.

Moreover, reporting of this particular subset of natural gas emissions is redundant. Distribution blowdown emissions are embedded in each natural gas supplier's compliance obligation under Section 95122, which is based on Subpart NN of 40 CFR Part 98 and involves mass-balance calculations for the amount of gas entering and leaving the gas distribution system. In addition, this requirement is inconsistent with United States Environmental Protection Agency (U.S. EPA) regulations, which do not require facilities to report emissions from blowdowns on the gas distribution segment.

PG&E therefore recommends removing the requirement to report equipment and pipeline blowdowns for natural distribution systems. To the extent ARB still deems it advisable to require independent reporting of vented emissions from natural gas distribution systems, PG&E requests staff introduce a new provision in Section 95153(g) that enables reporting entities to use conservative assumptions and annual summary data of replacement and maintenance activities performed to estimate vented emissions associated with such work. PG&E recommends the following addition to Section 95153(g):

(3) For natural gas distribution systems, use aggregated event data, rather than unique physical volumes, including but not limited to pipeline and meter replacements and other event categories that result in gas vented from the entity's natural gas distribution system. The information shall be categorized by pipeline or equipment size. Reporters in this category may, but are not required to, use Equations 13 or 14. In lieu of using Equations 13 or 14, average distribution system pressures, and temperatures, and gas composition (i.e., percent methane and CO_2), can be applied to report the annual volume of equipment and pipeline blowdowns in metric tons of CO_2 equivalent emissions. [OP 09.03 – PG&E]

<u>Response</u>: Staff has not proposed any amendments to section 95153(g). As such, the commenter's requested changes are beyond the scope of the current rulemaking. Notwithstanding this, ARB staff notes that reporting entities may use an engineering approach to estimate equipment blowdown emissions. Section 95153(g)(1) already allows the use of engineering estimates from best available data to estimate the unique physical volume. For this reason, ARB staff declines to make the suggested change. ARB staff also believes this information is important for understanding the fugitive methane emissions from pipeline systems. ARB staff does not plan to remove this requirement.

§95154 – Monitoring and QA/QC Requirements

I-5. Leak Measurement

Comment: Section 95154. ARB Should Allow Engineering Estimates When Direct Leak Measurements Cannot Be Collected Safely

Sections 95154(a)(1) through (5) provide the approved methods for conducting leak detection(s) of equipment leaks as required under Sections 95153(i), (m), (n), and (o). Sections 95154(a)(1) and (4) state that "an optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above the support surface." There is no provision that allows for engineering estimates for when there is a safety issue that prohibits a reporter to conduct direct leak measurement even with an optical gas imaging instrument. Where there are safety issues that prohibit direct leak measurements to be taken, PG&E recommends that ARB allow engineering estimates to be used. Therefore, PG&E recommends the following addition to Section 95154(a):

(6) In cases where measurements cannot be collected due to safety concerns the facility operator may utilize engineering estimates to report leaks. [OP 09.04 – PG&E]

Response: Section 95154(a)(1) allows use of an optical gas imagining instrument for measurements listed in sections 95153(i), (m), (n), and (o). This device allows the operator to detect and quantify leaks from a distance and this alternative work practice for monitoring equipment leaks allows reporters to safely make the required measurements. ARB staff believes this existing provision should alleviate the commenter's concerns. ARB staff wants to ensure the safety of reporting entities and is committed to working with reporting entities to ensure reporting can be handled safely. Based on this explanation, ARB staff declines to make the proposed change to ensure the accuracy of the reported data.

§95155 – Procedures for Estimating Missing Data

No comments were received on section 95155.

§95156 – Additional Data Reporting Requirements

I-6. New Reporting Requirements in this Section

Comment: ARB has amended the reporting requirements for onshore production facilities as follows –

(7) Barrels of crude oil produced using thermal enhanced oil recovery. This includes the crude oil fraction piped as an emulsion as defined in section 95102(a);
(8)Barrels of crude oil produced using methods other than non-thermal enhanced oil recovery. This includes the crude oil fraction piped as an emulsion as defined in section 95102(a);
(9) MMBtu of associated gas produced using thermal enhanced oil recovery. This includes the associated gas fraction piped as an emulsion as defined in section 95102(a);
(10) MMBtu of associated gas produced using methods other than non-thermal enhanced oil recovery. This includes the associated gas fraction piped as an emulsion as defined in section 95102(a).

As stated above, the term emulsion can be used in several different contexts and processes within the oil and gas industry. The current proposed definition of onshore production segment may cause confusion in the reporting requirements of 95156(a)(7)-(10).

Recommendation:
WSPA recommends that the requirements be amended (see red font) to reflect the specific definition of "emulsion" in the context stated in Section 95102(a)(149) as follows:

> (7) Barrels of crude oil produced using thermal enhanced oil recovery. **This includes any ~~the~~ crude oil fraction piped to an onshore petroleum and natural gas production facility as an emulsion from an offshore platform as defined in section 95102(a);**
> (8) Barrels of crude oil produced using ~~other than~~ **non**-thermal enhanced oil recovery. **This includes any ~~the~~ crude oil fraction piped to an onshore petroleum and natural gas production facility as an emulsion from an offshore platform as defined in section 95102(a);**
> (9) MMBtu of associated gas produced using thermal enhanced oil recovery. **This includes any ~~the~~ associated gas fraction piped to an onshore petroleum and natural gas production facility as an emulsion from an offshore platform as defined in section 95102(a);**
> (10) MMBtu of associated gas produced using methods ~~other than~~ **non**-thermal enhanced oil recovery. **This includes any ~~the~~ associated gas fraction piped to an onshore petroleum and natural gas production facility as an emulsion from an offshore platform as defined in section 95102(a).**

[OP 08.18 – WSPA]

Response: ARB staff declines to make the commenter's proposed changes because the changes do not add to the overall clarity of the definition. In order to alleviate any interpretational concerns around the term "emulsion," ARB staff added a definition in the 45-day language to section 95102(a) that sets up specific boundaries for what constitutes an emulsion.

I-7. Gas Liquid Fractionating Facility

Comment: ARB has amended the reporting requirement to add gas plants associated with onshore production facilities as follows:

(c) The operator of a natural gas liquid fractionating facility, or a natural gas processing facility, or an onshore petroleum and natural gas production facility with a gas plant that produces less than 25 MMscf per day must report the annual production of the following natural gas liquids in barrels corrected to 60 degrees Fahrenheit:
EPA and ARB do not define a gas plant as is currently included in the phrase. However, a natural gas processing plant is defined in Section 95150(a)(3). As such, WSPA requests that ARB rephrase the statement to include "natural gas processing plant" instead of "gas plant." In addition, the added phrase assumes that all natural gas processing plants are included in onshore production facilities. This may or may not be true. WSPA requests that ARB rephrase the statement to remove this assumption and clarify requirements for facilities that are subject to Cap & Trade requirements.
Recommendation:

WSPA recommends ARB rephrase the reporting requirement as follows (see red font):

(c) The operator of a natural gas liquid fractionating facility, ~~or a~~ natural gas processing facility as defined in 95150(a)(3), or ~~an onshore petroleum and natural gas production facility with a gas plant~~ a natural gas processing plant that ~~produces~~ processes less than 25 MMscf per day and is subject to Cap & Trade regulation must report the annual production of the following natural gas liquids in barrels corrected to 60 degrees Fahrenheit:

[OP 08.19 – WSPA]

Response: ARB staff partially agrees with this proposed change. The suggested language changes in the third line of the above edit were accepted and reflected in the 15-day modifications. ARB staff declines to put in the additional definitional reference or the Cap-and-Trade regulation addition. The definitional reference is not needed because the term "natural gas processing facility" is clearly referenced to section 95150(a)(3). Also, because the majority of natural gas processors are above 25,000 $MTCO_2e$, it is not necessary to explicitly state that only reporting entities subject to Cap-and-Trade are to report this item.

I-8. Onshore Natural Gas Processing Facilities

Comment: ARB had added the following reporting requirement:
"(d) Onshore natural gas processing facilities that have an annual average throughput of 25 MMscf per day or greater must also report the volume of associated gas, waste gas, and natural gas processed (MMBtu)."

Existing Section 95122(d)(1) and 40 CFR 98.406(a)(3) require natural gas processing facilities to report the following:

(3) Annual volumes in Mscf of natural gas received for processing.
Because these are existing requirements for natural gas processing facilities, the proposed section 95156(d) is redundant.
Recommendation:

Remove the redundant reporting requirement. [OP 08.20 – WSPA]

Response: At this time, ARB staff declines to make this proposed change. The requirements in section 95156(d) apply to waste gas, associated gas, and natural gas, while the section 95122 requirements only apply to natural gas. In order to ensure the allocation of allowances is calculated correctly, the requirements of section 95156(d) must stay in the regulation and ARB staff believes they are not redundant with section 95122.

§95157 – Activity Data Reporting Requirements

I-9. Materiality Assessment on Volumes of Associated Gas

Comment: Existing Sections 95156(a)(9) & (10) already require reporting of MMBtu of associated gas which is the covered product under the Cap & Trade regulation. In addition, ARB had proposed added the following reporting requirement:

"(19) For onshore petroleum and natural gas production and natural gas distribution combustion emissions, report the following:
***
(H) Annual volume of associated gas produced (Mscf) using thermal enhanced oil recovery and non-thermal enhanced oil recovery.

ARB states in its Initial Statement of Reasons that this requirement is being added in order to obtain a statewide average heat content for associated gas and to allow comparison of associated gas production data reported to ARB and to DOGGR. We understand the intention of this provision, but would like to inform ARB that the different level of granularity required by the ARB and DOGGR reporting may cause the data to not match neatly. In addition, volumes of associated gas production (Mscf) are activity data and are not covered product data and therefore should not be subject to materiality assessments.

Recommendation:
WSPA recommends ARB clarify this reporting requirement as follows:

"(19) For onshore petroleum and natural gas production and natural gas distribution combustion emissions, report the following:
***
(H) Annual volume of associated gas produced (Mscf) using thermal enhanced oil recovery and non-thermal enhanced oil recovery. This data is subject to conformance check only. [OP 08.21 – WSPA]

Response: ARB staff understands the concerns of the commenter and agrees that this information should not be subject to a material misstatement review by a third-party verifier. Because this requirement is in section 95157, which is a compilation of activity data, it is implied the information is only subject to a conformance check and not a material misstatement evaluation. ARB staff declines to make the change, but believes it is clear that the requirements are subject to conformance only during third-party verification.

Other 45-Day Comments Received.

J-1. Hydrogen Benchmark

Comment:

A. Hydrogen plants internal to a refinery should not be separated from the CWB refinery benchmarking.

ARB proposes to apply the "best in class" benchmark that was developed for the six merchant hydrogen plants to all internal refinery hydrogen plants, without adjustment or changes. Treating facilities with similar functions as identical does not represent the best technical or feasible approach…...

Requiring refineries to put a virtual 'fence' for purposes of monitoring and benchmarking between the integrated hydrogen plant and all of the other processes in the refinery is technically inequitable, infeasible and not necessary given the robust CWB methodology proposed for the rest of the refinery. Hydrogen plants that are internal to refineries should not be segregated from the refinery for the purpose of benchmarking; instead, a refinery should be benchmarked for all the process units within its boundaries.

Benchmarking merchant and internal hydrogen plants together is technically inequitable to the refineries with internal hydrogen plants.

- Merchant plants are newer and have the advantage of utilizing newer technology. These plants were built after 1994 and all use the pressure swing absorption technology, which inherently has fewer emissions.

- The Solomon methodology under CWB recognizes that refinery hydrogen plants are integrated into the refinery. Therefore including hydrogen plants within the refinery benchmark as a whole provides a fair allocation of allowances to hydrogen units.

- MRR CWB rules do not require metering of steam, electricity and other systems between process units. If the internal hydrogen plants are benchmarked separately these systems may not be monitored or metered to a level required by the Mandatory Reporting Rules.

- It would be difficult to monitor the emissions due solely to hydrogen production because hydrogen units inside a refinery share steam and other utilities with the rest of the refinery; these transfers are not monitored in the same way that they would be with a merchant hydrogen unit. Merchant plants meter their outputs in order to transact their contracts with the refineries.

The proposed merchant hydrogen benchmark of 20 allowances/mscf for the hydrogen plant sector is not appropriate for benchmarking internal refinery hydrogen plants.

- The currently proposed benchmark for hydrogen plants is based on 'best in class', and was developed to represent a benchmark for 6 merchant hydrogen plants. This is not an appropriate benchmark for the 18 hydrogen plants in California, many of which have a different design than the 'best in class' plant.

- Creating a hydrogen benchmark that is based on the most efficient merchant hydrogen unit is an unrealistic benchmark for hydrogen units within a refinery. Hydrogen units within the refinery are integrated into the refinery operations. A refinery might have optimized their hydrogen plant for additional steam rather than making steam elsewhere in the refinery; thus the hydrogen production would be lower and the emissions of their hydrogen unit would be higher than if the plant stood alone.

Having two separate hydrogen benchmarks would be the most equitable solution with the least additional study and equipment

A revised joint hydrogen plant benchmark could not be developed within the ARB's timeframe to meet regulatory deadlines for MRR. An attempt to calculate a separate benchmark that would include refinery and merchant hydrogen plants would be very difficult, since as described above, refinery hydrogen plants are closely integrated into the refinery, making it difficult to accurately assess and allocate emissions to the hydrogen plant. Substantial new data would be needed to correctly develop a technically sound benchmark. Many of the imports and exports into internal refinery hydrogen plants and the hydrogen and steam balance are not monitored at MRR level basis. Studies and equipment would be needed to obtain that data prior to creating a fair representative benchmark.

- ARB has created additional benchmarks when one benchmark is not representative or one group is substantially disadvantaged by the benchmark. ARB pointed out in the workshop that merchant plants are sufficiently different than hydrogen plants inside refineries such that merchant plants would receive as much as 20% more allowances under the CWB. This would be an indication that the two groups are significantly different in design and therefore demonstrates the justification two benchmarks.

- We recommend using the existing hydrogen plant benchmark of 20 allowances/mscf for merchant hydrogen plants and allowing internal hydrogen plants to be given allowances under the CWB benchmark with the rest of the refinery processes.

If one benchmark is ARB's only answer, then merchant plants and internal hydrogen plants could benchmark based on CWB.

This concept avoids trying to artificially separate integrated systems and would reward merchant systems for their efficiency. We cannot comment on the benchmark for merchant hydrogen plants, but the general practice of using 'best in class' instead of 90% of average appears to be creating an unnecessary and inequitable penalty for these operators and leads one to question why the Solomon CWB factor was not used as a basis for the merchant hydrogen benchmark.

In conclusion, we recommend that ARB include internal refinery hydrogen plants in the CWB benchmark for refining based on the technical and policy reasons described above.

We recommend that ARB implement this change by including the CWB factor for hydrogen plants in the CWB table and specify that 'mscf' refers to net million standard cubic feet of hydrogen production. [OP 10.01 – CC]

B. In the October 7, 2013 workshop, ARB proposed that on-site hydrogen plants be removed from the refinery allocation methodology and that on-site and off-site hydrogen plants be benchmarked based on the same benchmark applied to the merchant hydrogen facilities. WSPA believes it is inappropriate to benchmark based on the merchant facilities because they represent a minority of the hydrogen production1 in California and exclusively use Pressure Swing Adsorption which is the most current and efficient approach for hydrogen purification. This contrasts with On-site (refinery) hydrogen facilities in California and elsewhere in the world which utilize both PSA and Solvent technology. Use of a single benchmark representing broad industry practice that includes refineries and merchant plants rather than from use of a small subset of operators will result in a more equitable benchmark to facilities in the State.

   Recommendation: WSPA recommends utilizing the CWB methodology for refinery benchmarking because it is appropriate for California operations. Moreover, because it was developed through years of experience with over 200 refineries worldwide, use of the methodology ensures that refineries are equitably represented. If this approach is chosen by ARB for both on-site and off-site production it would meet ARB's first goal, as stated in the workshop, of providing consistent incentives for efficient operation of hydrogen plants.

   A more detailed description of the background on hydrogen plant operations is provided as Attachment A. [OP 23.03 – WSPA]

Response: This comment relates to a proposed amendment from the separate Cap-and-Trade Program rulemaking proceedings. Therefore, this comment is outside the scope of the amendments included in the MRR rulemaking proceeding.

J-2a. CWB Benchmark

Comment: Proposed CWB Benchmark Calculation

We are concerned that the analysis presented on October 7 showed that the CWB benchmark for 2014 will not provide the expected 84.5% (0.944 cap * 0.9 stringency) allowances, but rather provides only 83%. We would like to review ARB's methodology for calculating the refinery benchmark, particularly with respect to the details of how hydrogen plants were treated. [OP 10.02 – CC]

J-2b. CWB Benchmark

Comment:

Revisions to Support Use of CWB in Refinery Benchmarking

Kern is supportive of Cap & Trade Staff's proposal to adopt the CWB allocation methodology utilizing the Solomon Process Unit Factors and including Solomon's factors for off-sites, non-energy utilities and "non-crude sensible heat" and recognizes that certain proposed amendments to MRR are in support of refinery benchmarking. Staff's proposal to utilize the CWB methodology, inclusive of the off-sites adjustment and utilizing all of the process unit factors, ensures the accuracy of the methodology, which is critical for California's smaller, less complex refineries. These factors can play a very significant role in the operation of facilities like Kern and their corresponding allocation determinations.

Proposed language in Section 95113(l)(4)(B) references the use of functions and factors in Table 1 of the same section for the purpose of calculating the total facility CWB. While Kern supports the adoption of the CWB methodology, the functions and factors included in the current 45-day amendment package are associated with the Carbon Weighted Tonne methodology and therefore are not accurate for use within CWB. ARB Staff held a workshop on October 7, 2013, presenting a working document titled "Language to Support Complexity Weighted Barrel (CWB)" for stakeholder review. The working document indicated regulatory text changes that will be necessary in the MRR, intended for a subsequent 15-day amendment package, to support use of CWB. Kern is anticipating the release of this 15-day package containing revised regulatory language and a revised Table 1 with appropriate functions and factors specific to CWB, in line with that provided to stakeholders at the workshop.

Kern notes that certain revisions and/or corrections to this working document will be required prior to incorporation into the MRR in order to accurately calculate the off-sites and non-crude sensible heat adjustments. Kern will comment further, as may be necessary, upon review of the 15-day amendment package addressing this supportive text within the MRR.

[OP 35.02 – KOR]

Response: (this response effective for J-2, comments a and b).
This comment relates to a proposed amendment from the separate Cap-and-Trade Program rulemaking proceedings. Therefore, this comment is outside the scope of the amendments included in the MRR rulemaking proceeding.

J-3. Prevent Double Reporting

Comment: SMUD Recommends that the Board Direct ARB Staff to Develop a Minor Amendment to the Cap-and-Trade Regulation to Prevent a Duplicate Compliance Obligation for SMUD's Unique Circumstances. SMUD is recommending a slight modification to the Cap-and-Trade Regulation to reduce SMUD's exposure for this unique situation. In particular, SMUD recommends adding a
new subsection (c)(5) to Section 95852 of the Cap-and-Trade Regulation, as follows:
(c) Suppliers of Natural Gas. A supplier of natural gas covered under sections 95811(c) and 95812(d) has a compliance obligation for every metric ton CO2e of GHG emissions that would result from full combustion or oxidation of all fuel delivered to end users in California contained in an emissions data report that has received a positive or qualified positive emissions data verification statement or for which emissions have been assigned, less the fuel that is delivered to covered entities, as follows:
(5) Publicly-owned natural gas utilities that supply natural gas to covered entities which include the utility shall not have a compliance obligation if the utility can demonstrate that its deliveries are made exclusively to the covered entities.
The suggested amendment of the Cap-and-Trade Regulation would be very narrow in scope because it would apply to just publicly-owned natural gas utilities that distribute gas on a pass-through basis. It would also be limited to the situation where all gas supplied by the pipeline is to covered entities, which already report and hold compliance instruments. Most importantly, the proposed amendment would do away with the potential to saddle an electric utility with duplicate liability for a compliance obligation as a result of an internal, pass-through, pipeline system.

Response: This comment relates to a proposed amendment from the separate Cap-and-Trade Program rulemaking proceedings. Therefore, this comment is outside the scope of the amendments included in the MRR rulemaking proceeding.

J-4. Refinery Benchmark Calculation Transparency

Comment: In the interest of transparency, the calculation method used to allocate allowances based on the refinery benchmark must be made public. Attempts to duplicate the overall calculation method (not for individual facilities) used by ARB have failed. Specifically, the CWB benchmark for 2014 should provide 84.96% (0.944 cap * 0.9 stringency) allowances based on the 2014 cap stringency and the 10% "haircut" policy. ARB stated at the workshop that their proposed benchmark would provide only

83% when using the CWT index. Converting CWT to CWB should yield the same percentage reduction.

Recommendation: ARB should release the calculation method so that stakeholders understand the process and data used in the analysis. [OP 23.05 – WSPA]

Response: This comment relates to a proposed amendment from the separate Cap-and-Trade Program rulemaking proceedings. Therefore, this comment is outside the scope of the amendments included in the MRR rulemaking proceeding.

J-5. Definition of Atypical

Comment: Valero recommends that ARB employ the accepted and recommended definition of "atypical" in determining which facilities should be treated outside of the CWB benchmark process. [OP 22.01 – VC]

Response: This comment relates to a proposed amendment from the separate Cap-and-Trade Program rulemaking proceedings. Therefore, this comment is outside the scope of the amendments included in the MRR rulemaking proceeding.

J-6. Treatment of Allowances for Power Generated and Consumed

Comment: Treatment of Allowances for Power Generated and Consumed

ARB has recognized that emissions related to electricity are significant and that the allocation methodology should be equitable to EITE facilities regardless of the source of power. Many facilities generate power with on-site CHP facilities, while others purchase power from utilities or third party CHP's. However, ARB's recommended approach referred to as the "ARB Standard approach" in the October 7, 2013 workshop, does not, in and of itself, insure equitable treatment of EITE facility energy-related emissions. Rather, it relies on anticipated regulatory action by the CPUC to insure that free allocations from ARB and revenue sharing required by the CPUC meet the objective of equitable treatment and that equitable treatment is extended to facilities served by Publically Owned Utilities. While it is clear that both the ARB and the CPUC play a role in the development and implementation of the free allocation methodology, it is problematic that ARB's action will be taken before final approval of a methodology by the CPUC.

Recommendation: In order to ensure that the ARB and CPUC methods are consistent with respect to treatment of power, WSPA recommends that ARB adopt a resolution that: i) allows ARB to confirm that ARB and CPUC regulations achieve the desired equitable resolution, ii) provides for reopening of ARB's allocation method if it is not resolved equitably, and iii) ensures that similar objectives are met for facilities connected to Publicly Owned Utilities. [OP 23.02 – WSPA]

Response: This comment relates to a proposed amendment from the separate Cap-and-Trade Program rulemaking proceedings. Therefore, this comment is outside the scope of the amendments included in the MRR rulemaking proceeding.

J-7. NGL Processers

Comment:

Natural Gas Liquids Processors and the Product Output-Based Methodology

Inergy is a natural gas liquids processor. It is Inergy's understanding that its allowances are to be calculated using the product output-based methodology. Inergy reiterates here the unique characteristics of natural gas processing facilities, to demonstrate why it is critically important to clearly define the terms used for inputs to reporting requirements and allowance calculations.

As a natural gas liquids processor, Inergy does not "produce" natural gas from underground sources. Rather, it processes, stores, or distributes or resells unfractionated gas liquids delivered by others, typically natural gas producers. Processing may be minor, such as drying or odorizing, or it may involve fractionating and reforming natural gas liquids. With respect to the latter category, Inergy may process or fractionate the unfractionated liquids into a variety of "products", such as methane, ethane, propane, butane, mixed butane, normal butane, isobutene, and natural gasoline. After processing, natural gas generally is delivered by pipeline to a public utility, and liquids are shipped to customers by truck and rail. Inergy may also store gas and liquids for customers, and, from time-to-time, Inergy may purchase a "product" and resell it. Other natural gas liquids processors may undertake similar activities, or they may operate differently.

Given the potential range of activities that natural gas processing facilities may perform, it is critical that the California Air Resources Board ("CARB") clearly and precisely define "product", "product output", "production" and related terms for purposes of reporting requirements under the MRR and calculating allowances under the Cap-and-Trade Regulation. As currently drafted, the proposed revisions to the Cap-and-Trade Regulation, in Section 95891 and Appendix C, provide some guidance as to how to account for both gas and liquids under the product output-based methodology, but they do not define what constitutes "product," "production" or "product output" in the first instance. The proposed revisions to the MRR contain the same flaw (*see, e.g.*, Proposed Amendments to the MRR, Appendix A to Staff Report, Section 95156(c)). Thus, it is not possible to know what "output" reported to CARB will be used by the Executive Officer to calculate allowances, as contemplated in product output-based allocation methodology set forth in Section 95891(b) of the proposed revised Cap-and-Trade Regulation (*see, e.g.*, definition of "$O_{a,t-2}$").

In order to resolve this uncertainty, and to avoid the potential for disparate application of the product output-based allowance methodology to similarly situated natural gas liquids processing facilities, the terms "product", "product output," "production" and other relevant terms must be defined, both in the Cap-and-Trade Regulation and the MRR.

[OP 32.02 – IWC]

Response: This comment relates to a proposed amendment from the separate Cap-and-Trade Program rulemaking proceedings. Therefore, this comment is outside the scope of the amendments included in the MRR rulemaking proceeding.

J-8. True-Up Allowances

Comment: True-up Allowances

Inergy supports replacing the November 1 date by which allowances will be annually allocated to eligible covered entities with the October 15 date (*see* revised section 95870(e)(1) in the Cap-and-Trade Regulation), and recommends that CARB adopt the change. This change helps resolve the allowance timing issue Inergy described in its August 2, 2013 comments on the proposed revisions to the Cap-and-Trade Regulation. [OP 32.03 – IWC]

Response: This comment relates to a proposed amendment from the separate Cap-and-Trade Program rulemaking proceedings. Therefore, this comment is outside the scope of the amendments included in the MRR rulemaking proceeding.

J-9. Treatment of Energy Generated Offsite and Onsite

Comment: We would like to see ARB's case studies for treatment of imported electricity to ensure that results will be equitable in all cases. We understand that ARB will provide allowances for direct emissions and CPUC will provide allowance value for indirect emissions. These allocations would be based on production using the same CWB benchmark. ARB discarded WSPA's recommendation to use a ratio approach to level the playing field for onsite and offsite generation based on their expectation of the CPUC's regulatory action. Due to the separation of the two agencies and time lag in the CPUC rulemaking process, we recommend that ARB adopt a resolution that recognizes this issue and would allow ARB to reopen the matter if it is not resolved equitably. [OP 10.03 – CC]

Response: This comment relates to a proposed amendment from the separate Cap-and-Trade Program rulemaking proceedings. Therefore, this comment is outside the scope of the amendments included in the MRR rulemaking proceeding.

J-10. Request to Update ISOR

Comment: The reference to SCPPA in the initial statement of reasons is incorrect [OP 12.10 – SCPPA]

Response: Because the Initial Statement of Reasons (ISOR) is part of the regulatory record, staff is not able to amend the document. However should there be concern over the details, the original letter OP 12.10 is a public record, and will serve as explanation. ARB staff will take note of this discrepancy regarding the electricity generating facility at 164 West Magnolia. Additionally, in order to ensure correct contact information, the commenter should make sure that its information in Cal e-GGRT is up to date.

J-11. Comment Period

Comment:

Comment Period

The notice of public hearing for both the MRR and Cap & Trade proposed orders state that comments are due on October 23rd at noon (Pacific) and that the public hearing is scheduled for October 24th at 9 am. As a procedural issue, Valero does not feel that industry has sufficient time to comment on the proposed amendments in such a way that CARB can fully address the comments and incorporate appropriate changes to its regulatory language before the public hearing with the CARB Board. Further, the notice states "ARB requests that written and email statements on this item be filed at least 10 days prior to the hearing so that ARB staff and Board members have additional time to consider each comment." While this language is a request and not a requirement, the fact that the Board hearing is scheduled to occur the morning after the deadline for comments makes October 13th (Sunday) the *de facto* deadline for submitting comments. This, in effect, shortens the comment period to 35 days and also short circuits discussions within trade association and between trade associations and CARB, especially pertaining to entirely new sections of the regulation (i.e., pertaining to reporting of Toxic Air Pollutants and Criteria Pollutants under provisions of the Adaptive Management Plan). Valero suggests that CARB incorporate all appropriate comments into the regulatory language for the Board hearing, as long as the comments are submitted by the 23rd.

[OP 13.02 – VC]

Response: Mandatory Reporting and Cap-and-Trade are two separate regulations at ARB, each following the requirements of the Administrative Procedures Act for noticing updates and changes. ARB staff working on both regulations encourage stakeholders to reach out during the regulatory update process in order to minimize confusion.

J-12. Verification Deadline

Comment: During the July 2013 workshops on the Cap-and-Trade and Mandatory Reporting Regulations, the ARB discussed the possibility of adjusting the timeline for allocation of allowances to October 15th and the verification deadline would be moved to August 15th.

TID was concerned that moving these deadlines could make the verification and reporting process more difficult. Under the current timeframes, compiling the required data and obtaining verification services requires significant staff resources. Any delays in information collection or verification could jeopardize meeting the deadlines, which appear to be strictly enforced. Thus, TID supports the ARB's decision to not adjust the verification and reporting deadlines. [OP 33.02 – TID]

Response: No change required. Staff retained the current reporting and verification deadlines as suggested.

J-13. Compliance Assistance and Honest Mistakes

Comment: How much compliance assistance will there be for new reporters under MRR? What are the consequences if the new reporters make an honest mistake? [T 09.01 – AB]

Response: Since the beginning of the GHG reporting program, ARB staff has provided assistance to new and existing reporters through direct phone and in-person discussions, publicly available guidance and training materials, and live webinar-based training for reporters. ARB staff will continue with this type of assistance on an ongoing basis to ensure reporting entities (whether new or existing) understand the requirements of the reporting regulation. It is important to note that pursuant to California law, and as specified in section 95107 of the reporting regulation, all mistakes, whether honest or intentional, are potentially subject to the enforcement requirements of section 95107. As such, it is important for all reporting entities to raise questions with ARB staff early on during the reporting process.

J-14. Display of Covered Emissions for Natural Gas Suppliers

Comment: PG&E requests that MRR data be presented in a way that provides full transparency as to the categories of emissions that will be covered in each compliance period of cap-and-trade for each reporting entity. In releasing the “2011 GHG Facility and Entity Emissions Detailed Spreadsheet” ARB took an important step in this direction by presenting a “covered emissions” column. This spreadsheet defines covered emissions as follows:

“Covered emissions” which are computed by ARB, mean all emissions included in a compliance obligation under section 95852 through 95852.2 of the cap-and-trade regulation, regardless of whether the cap-and-trade regulation imposes a compliance obligation for the data year. Covered emissions are equal to the Total CO2e emissions minus emissions from sources or substances that are not considered covered emissions (such as biofuels). Covered emissions are only displayed for reports subject to the cap-and-trade requirements, and a value of "0" (zero) is displayed for reports which do not have covered emissions under the cap-and-trade program, such as facilities emitting <25,000 metric tons of covered CO2e emissions that are not opt-in facilities.

However, this presentation may have generated some confusion for the following reasons:

- Covered emission values for natural gas suppliers were not presented as the subset of emissions which generate a compliance obligation beginning in the second compliance period of cap-and-trade (i.e., there was no netting to account for fuel supplied to other covered entities).

- It is not always clear if entities were electricity importers (covered beginning in the first period) or fuel suppliers (covered beginning in the second period).

- PG&E requests that future detailed MRR spreadsheets include columns that explicitly identify “Narrow Scope Covered Emissions” and “Broad-Scope Covered Emissions” for each reporting entity with an ARB ID number. If possible, the 2011 dataset should also be updated to reflect these categories. Clarity in presentation of this information is critical to market participants’ ability to accurately track emission trends driving the fundamentals of the Cap-and-Trade market.

For summary data, display "narrow-scope" and "broad-scope" covered emissions for natural gas suppliers. [OP 09.07 – PG&E]

Response: On November 4, 2013, ARB released the 2012 and updated 2011 summary spreadsheets for reporting entity emissions (http://www.arb.ca.gov/cc/reporting/ghg-rep/reported-data/ghg-reports.htm). In these spreadsheets, additional columns were added to ensure the narrow-scope and broad-scope covered emissions were distinguishable for each reporting entity subject to the reporting regulation.

J-15. Provide Aggregated Combined Heat and Power Information

Comment: PG&E supports the 2012 amendments to 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.

Efficiency and GHG performance is the essential driver of cogeneration/combined heat and power (CHP) policy in California. We ask that ARB make use of this data by developing and publicly presenting aggregated CHP efficiency information collected through the Mandatory Reporting Regulation and developing 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 believe that this approach will help inform the implementation of CHP policies, assist with future updates to ARB’s Scoping Plan, and support California’s AB 32 GHG reduction goals. [OP 09.08 – PG&E]

Response: ARB staff appreciates the commenter’s support. With respect to the specific request that ARB publish aggregated CHP efficiency information, ARB staff notes that this rulemaking did not propose to include any such actions as part of the regulatory language. As such, this comment is outside the scope of this rulemaking.

J-16. Incorporation of WSPA Letter

Comment: Valero incorporates WSPA’s comment letter (OP 08) by reference. [OP 13.01 – VC and OP 14 – VC]

Response: Please see responses related to OP 08.01-21 in Responses to comments A-5, A-7, A-8, A-25, A-28, A-32, A-37, A-40, A-42b, A-42n, A-43, A-44, C-3, D-2 a, b, c, d, D-3, D-4, D-8, H-1, H-2, H-6, I-1, I-3, I-6, I-7, I-8, I-9, J-1b, J-4, J-6.

J-17. Refinery Workshop (October 7, 2013)

Comment: WSPA indicates that it is reviewing issues raised at an October 7, 2013 workshop and will work with ARB to identify questions and comments that should be submitted to ARB prior to final approval by the Board. [OP 08.22 – WSPA]

Response: This comment does not propose any modification to the regulatory language, and a response is therefore not required. ARB staff appreciates the commenter's commitment to raising issues with staff.

15-DAY COMMENTS

AND STAFF RESPONSES

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

§95100 – Purpose and Scope

K-1. 95100 Alignment of federal GHG reporting and California's GHG Reporting

Comment: Section §95100(c) of the Purpose and Scope in Subarticle 1 incorporates various provisions of title 40, Code of Federal Regulations, Part 98 (40 CFR 98). These provisions are a portion of the U.S. Environmental Protection Agency (U.S. EPA) Final Rule on Mandatory Reporting of Greenhouse Gases, but only incorporate requirements promulgated in the Federal Register through April 25, 2011. U.S. EPA has promulgated several rule revisions since this date, and California reporters required to use methodologies from 40 CFR 98 now have to follow two different versions of the federal rule. This adds burden, increasing compliance costs, and is confusing for reporters. The post April 25, 2011, U.S. EPA revisions include technical corrections to improve the quality of data and the accuracy of emission estimates. If adopted, the proposed MRR referencing an older version of the federal rule will result in less accurate GHG emissions reporting. SoCalGas and SDG&E request that the California Air Resources Board (ARB) MRR amendments reference the most current version of the U.S. EPA rule. Further, we request that ARB provide reasons and guidance regarding why ARB is not incorporating the post April 25, 2011, revisions to 40 CFR 98. SoCalGas and SDG&E believe that these proposed MRR amendments provide the best opportunity to reconcile the state and federal rules, thus reducing confusion and reporting burden.

[F 17.01 – SU]

Response: Staff has not proposed any amendments to section 95100(c). As such, the commenter's requested changes are beyond the scope of the current rulemaking. Notwithstanding this, ARB staff notes that no U.S. EPA rule updates have been incorporated by reference since the April 25, 2011 update. In its 2012 MRR update, staff directly incorporated Subpart W into the reporting regulation (sections 95150-95158). Whenever a new update comes out, ARB staff evaluates its content and then determines whether it supports the goals of the reporting program. In some cases, the U.S. EPA update does not align with the existing California reporting regulation or the stringency for the Cap-and-Trade Program, so the update is not incorporated. While this may cause small disconnects, ARB staff believes the general reporting requirements remain consistent between the ARB reporting regulation and the U.S. EPA reporting rule to reduce the reporting burden of entities.

§95102 – Definitions

K-2. Clarify Definitions for Poultry Product Data

Comment: We at Foster Farms have the following comments regarding the proposed changes to the regulation for the mandatory reporting of greenhouse gas emissions. Our comments are limited to certain new definitions appearing in the proposed regulation and are editorial in nature. The comments are intended to clarify the definitions and thereby facilitate compliance.

In Section 95102 we request the following changes to the definitions of "poultry deli products", "protein meal" and "whole chicken and chicken parts":

Revised the definition of "poultry deli product" as shown below to specifically include the term "franks", and to account for the transfers of these products to other facilities for additional processing (e.g., sending franks to a facility where they will be further processed to become corn dogs). We recommend the following wording:

(62) "Poultry deli product" means the products, including corn dogs, sausages, and franks, that contain a significant portion of pre-processed poultry, that are cooked and sold wholesale or retail, or transferred to other facilities.

Revise the definition of "protein meal" to "protein meal and fat" to specifically include all significant rendered products including poultry fat and feather meal. We recommend the following wording:

(65) “Protein meal and fat” means meal, feather meal and fat rendered products from poultry tissues including meat, viscera, bone, blood, and feathers.

Revise the definition of “whole chicken and chicken parts” to provide additional examples of parts and to account for transfers to other facilities for additional processing (e.g., sending wings to another facility for seasoning and cooking). We recommend the following wording:

(89) “Whole chicken and chicken parts” means the whole chicken or chicken parts (including breasts, wings, drums, and thighs) that are packaged for wholesale or retail, or transferred to other facilities.

We understand that these comments may be too late for consideration in this revision to the regulation. We do note that there was a limited comment period for this regulatory change before it was heard by the Board. If the comments cannot be considered for the current regulatory change we then request that they be considered in the development of compliance guidance documents for this regulation. We would be pleased to discuss any questions or concerns you may have regarding these comments. Thank you for your consideration of our requests. [F 02.01 – FF]

Response: The proposed changes are technical clarifications which do not affect the reporting requirements or scope, and therefore, ARB declines to make the suggested changes. ARB will work with stakeholders to ensure the reporting requirements are understood, and will provide clarifying guidance documents if needed.

K-3. Specified Source Definition

Comment: TransAlta requests ARB to clarify who is eligible to be the first seller of a specified source in the market path, by altering the specified source definition as follows: (432) “Specified source of electricity” or “specified source” means a facility or unit which is permitted to be claimed as the source of electricity delivered. The reporting entity must be a Generation Providing Entity of the source or have either full or partial ownership in the facility/unit, or have a written power contract to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity procured from an asset-controlling supplier recognized by the ARB.” [F 04.03 – TA]

Response: ARB staff believes the definition of “specified source of electricity” is already clear as to which types of entities and electricity classify as “specified sources.” As such, ARB staff declines to make the requested change. See also response to comments A-20a-c.

K-4. 95102(a) Clarify Definition for Specified Source

Comment: A source of confusion and uncertainty in the wholesale power market results from ambiguity in MRR § 95102(432) and § 95102(20), the definitions of "specified source" and "asset-controlling supplier," respectively. It is critical that ARB modify these definitions so that there is a clear distinction between an entity registered as an ACS and the system of an ACS. The current MRR does not do this and ARB's goal in making changes "… to ensure electric power entities know how to effectively report their purchases of asset controlling supplier power" cannot be met without clarifying these definitions.

The definition of "specified source" states that a "[s]pecified source also means electricity procured from an asset-controlling supplier." The notion of a "specified source" is that of a generation source throughout the MRR, rather than that of an entity that owns or has rights to the output of the generation source. Under the current definition of a specified source there is insufficient clarity to distinguish between these two very different ideas:

- The system of an ACS (in Powerex's case, the BC Hydro system) is a source of power and acts as the source of generation on a NERC e-Tag. As compared with

- An ACS that is an ARB registered commercial entity that contracts, imports, exports, arranges transmission and is the "purchasing-selling entity" on the NERC e-Tag.

The two are not the same, and must be treated differently within the MRR. Parts of the MRR recognize this important distinction. See for example the MRR's definition of "written power contract," which provides that "[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." (MRR § 95102(351)(emphasis added.). It is critical that the MRR recognize this distinction consistently throughout the Regulation. To leave it internally inconsistent creates ambiguities that foster confusion within the industry. This inconsistency is made clear by the case of Powerex. Powerex has the ability to source power from a number of sources other than the BC Hydro system. To avoid ambiguity, the following modification should be made to the definition of "specified source":

> **§95102(432)** "Specified source of electricity" or "specified source" means a facility or unit which is permitted to be claimed as the source of electricity delivered. The reporting entity must have either full or partial ownership in the facility/unit or a written power contract to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity delivered from the system of ~~procured from~~ an asset-controlling supplier recognized by the ARB.

[F 19.02a – PX]

Response: See responses to comments A-10 and A-20a-c.

K-5. 95102(a) Clarify Definition for Asset-Controlling Supplier

Comment: The inconsistency problem arises in the MRR's definition of asset-controlling supplier. MRR § 95102(20) states that "[a]sset-controlling suppliers are considered specified sources." The MRR's definition of an ACS should be re-worded so as to be consistent. We suggest making the following modification to do so:

> **§95102(20)** "Asset-controlling supplier" means any entity that owns or operates inter-connected electricity generating facilities or serves as an exclusive marketer for these facilities even though it does not own them, and is assigned a supplier-specific identification number and system emission factor by ARB for the wholesale electricity procured from its system and imported into California. An Asset-controlling supplier's system may be ~~are~~ considered a specified source~~s~~.

If ARB does not amend the definitions [for specified source and asset controlling supplier], in the alternative, ARB should provide clarity in its FSOR to remove the ambiguity. Powerex recommends that the FSOR include language along the lines of the following:

> **Response:** Our intent for specified sources is to apply similar treatment between an electricity generating facility or generating unit and the inter-connected electricity generating facilities that make up the system of an asset-controlling supplier. We agree that specified sources are a source of generation as identified on a NERC e-Tag. The same applies to the system of an asset-controlling supplier. The MRR requires that specified sources are directly delivered to a California balancing authority and as a result it is only deliveries from the system of the asset-controlling supplier as demonstrated on the NERC e-Tag that may be the specified source and not simply the presence of the entity registered as an asset-controlling supplier on the NERC e-Tag.

[F 19.02b – PX]

Response: See response to comment A-10 for the definition of asset-controlling supplier. For the reasons stated in response to comment A-10, ARB declines to include the commenter's suggested response in the FSOR. See also response to comments A-20a-c.

K-6. Emulsion Definition

Comment: WSPA recommends that the phrase added to 95150(a)(2) be clarified to reflect the specific definition of “emulsion” in the context stated in Section 95102(a)(149) as follows:

> “Crude oil and associated gas that is piped to an onshore production facility as an emulsion from an offshore platform as defined in section 95102(a) must follow the requirements of section 95156(a) (7)-(10) and meet the metering requirements of section 95103(k) by measuring the emulsion before the first separation tank at the onshore production facility and not at the offshore platform.”

Also, revise the definition in 95150(a)(2) to include “or to which emulsion is transferred” to make it consistent with the proposed amended definitions of “facility” and “onshore petroleum and natural gas production facility” found elsewhere in the MRR and Cap and Trade Regulations.

Finally, ARB should make definitions in the Cap and Trade and MRR regulations consistent. For example, the definitions of “Onshore Petroleum and Natural Gas Facility” are not consistent between the Mandatory Reporting Regulation and Cap and Trade Regulation:

> a) Cap and Trade definition of "facility" (proposed 134(C), p. 19-20): "all petroleum and natural gas equipment on a well-pad, or associated with a well pad or to which emulsion is transferred"
>
> b) MRR definition of "onshore petroleum and natural gas production facility" (proposed 326, p. 15): "all petroleum and natural gas equipment on a well-pad, or associated with a well pad or to which emulsion is transferred"
>
> c) MRR definition of "facility" (proposed 171, p. 11): "all petroleum and natural gas equipment on a well-pad, associated with a well pad or to which emulsion is transferred" [F 10.05 – WSPA]

Response: See response to comment I-1.

K-7. Facility Definition – Cap and Trade

Comment: Revise the Cap and Trade definition of "facility" (proposed 134(C), p. 19-20) and the MRR definition of "onshore petroleum and natural gas production facility" (proposed 326, p. 15) to be consistent with the MRR definition of "facility" (proposed 171, p. 11).

For the revised definitions of "facility" (proposed 171, p. 11) and "onshore petroleum and natural gas production facility" (proposed 326, p. 15) strike the word "hydrocarbon" from the phrase "single hydrocarbon basin." However, the same change has not been made to the relevant definition of "facility" in the Cap and Trade regulation (proposed 134(C), p. 19-20). [F 10.04 – WSPA]

Response: See response to comment I-1.

K-8. Intrastate Pipeline Definition

Comment: The proposed amendment includes the following definition for intrastate pipeline: “Intrastate pipeline” means any pipeline or piping system wholly within the state of California that is delivering natural gas to end-users and is not regulated as a public utility gas corporation by the California Public Utility Commission (CPUC), not a publicly-owned natural gas utility and is not regulated as an interstate pipeline by the 4 Federal Energy Regulatory Commission. For purposes of this article, intrastate pipeline operators that physically deliver gas to end users in California are considered to be Local Distribution Companies [LDC]. Facilities that receive gas from an upstream LDC and redeliver a portion of the gas to one or more adjacent facilities are not considered intrastate pipelines.”

Our understanding is that a facility which receives gas from an upstream LDC and redistributes the gas to downstream facilities is not an intrastate pipeline. However, it is not clear whether a pipeline is an intrastate pipeline in the following situations:

> a) The facility processes or mixes gas received from an upstream LDC with other gases and redistributes the processed gas,
>
> b) The total gas redistributed is a greater amount of gas than the amount that was received, and,
>
> c) The gas received or redistributed is part of a gas exchange. Recommendation: WSPA recommends ARB clarify the above questions in the regulation or provide a Guidance document for reporters.

[F 10.06 – WSPA]

Response: See response to comment A-5.

K-9. Onshore Petroleum and Natural Gas Production Facility Definition

Comment: ARB includes in the definition: “Onshore petroleum and natural gas production facility” means all petroleum or natural gas equipment on a well pad, or associated with a well pad or to which emulsion is transferred and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator that are located in a single hydrocarbon basin as defined in 40 CFR §98.238.

When a commonly owned cogeneration plant is within the basin, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant. Where a person or operating entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Based on ARB's Facility Guidance Document (http://www.arb.ca.gov/cc/reporting/ghgrep/ guidance/ghg_oilgasfacility_definition.pdf, dated 2/29/12, page 3) for Petroleum and Natural Gas Systems, the "associated with" term is also inclusive of cogeneration facilities that supply steam and/or electricity to the well pad.

Cogeneration units located in the basin are included in the Onshore Production facility only if these units supply steam and electricity to the well pads. This guidance is consistent with EPA's guidance on facility determination of industry segments. However, the text added to the existing definition requires cogeneration plants located in the basin to be included in the Onshore Production facility regardless of the industry segment that the units serve. Was this ARB's intention and if so, will the guidance document change to reflect that? In addition, should the reporters re-assign cogeneration plants to facilities based on the above definition for the 2013 report?

Recommendation: WSPA recommends ARB revise the statement added to the definition as shown in red font below: When a commonly owned cogeneration plant is within the basin and serves well pad operations, the cogeneration plant is only considered part of the onshore petroleum and natural gas production facility if the onshore petroleum and natural gas production facility operator or owner has a greater than fifty percent ownership share in the cogeneration plant. [F 10.07 – WSPA]

Response: See response to comment A-7.

K-10. Total Refinery Input, Non Crude Input, Process CWB Definitions

Comment: CWB for "Non-Crude Sensible heat" recognizes that there is real energy demand to preheat non-crude raw materials prior to entering the process units. Acknowledging this energy consumption provides consistency between reported emissions and reported CWB. Determination of this volume should EXCLUDE volumes of crude oil fed to the Atmospheric Crude Distillation unit(s) as the assigned CWB factor for Crude Units includes the pre-heat (sensible heat) of crude feed to process temperature. Recommendation: WSPA recommends the proposed definition (69) be retained and that definitions (45) and (50) be revised as follows:

95102(a)(69) "Total Refinery Input" means the total volume of the following brought in to the refinery: crude oil and condensate excluding basic sediment and water; finished product additives such as dyes, diesel pour point depressants and cetane improvers;

antiknock compounds; other raw materials including crude diluents; feedstock from outside the refinery which is processed in other process units; or blend stock blended into refinery products.

95102(a)(45) "Non-Crude Input" means the total volume of non-crude raw materials to the refinery processed in process units at the refinery, excluding returns from a lube refinery or a chemical plant within a refining/petrochemical complex and excluding nonprocessed blend stock.

96102(a)(50) "Process CWB" means the total complexity-weighted barrels of a refinery excluding those contributed by "Offsites and Non-Energy Utilities" and "Non-Crude Sensible Heat". [F 10.13a – WSPA]

Response: ARB staff declines to make the commenter's changes. As written the definition for "non-crude input" is clear and unambiguous. Adding the suggested change adds uncertainty to the definition because the term "non-crude raw materials" is also not defined. The same holds true to the modifications to "Process CWB." ARB staff believes the existing location of these terms (offsites and non-energy utilities) and the concept of non-crude sensible heat are sufficient to achieve accurate reporting of the CWB throughputs.

K-11. 95102(a) Pipeline Quality Natural Gas Definition

Comment: SoCalGas and SDG&E have previously provided written comments regarding the definition of "Pipeline Quality Natural Gas" and its application within the regulation. While some of our concerns have been addressed, issues remain that we feel require additional consideration.

In MRR Section 95102, Definitions, the use of the word quality in the definition of "Pipeline Quality Natural Gas" is used to define a default range for energy content (British thermal Unit – BTU), which determines the methodology for MRR emissions calculation. SoCalGas and SDG&E request the word quality be eliminated from the definition of pipeline natural gas to avoid the issues discussed below. Such a change would not affect the meaning or function of the term within the MRR.

SoCalGas and SDG&E request the removal of the word quality because it implies a standard or grade having an intrinsic value, characteristic or feature. The word quality often implies excellence or grade and conveys a positive connotation, whereas anything not labeled with the word quality creates a negative connotation. The use of the word quality in the definition of pipeline natural gas may create concern for natural gas customers whose purchased natural gas falls outside of the specified default range in the MRR definition. Because of the MRR definition's implication of quality, a customer may think their purchased gas is not quality natural gas, despite the fact it meets the California Public Utility Commission's (CPUC) natural gas specifications.

The CPUC establishes natural gas specifications to which California's utilities must adhere for purposes of receiving, transporting, and delivering natural gas to their customers. Because the CPUC has overall State jurisdiction over natural-gas quality issues, ARB should remove the word quality from the definition of pipeline natural gas or choose a different term to define the default range for calculation purposes under MRR to avoid the impression that ARB is asserting authority over the CPUC on natural gas quality issues.

Additionally, SoCalGas and SDG&E remain concerned that the definition of pipeline natural gas states that pipeline quality natural gas contains at least ninety percent methane by volume, and request that this be changed to align with the CPUC specification for methane content. The CPUC has exclusive jurisdiction over the quality and composition of natural gas delivered to utility customers in California. The methane content of at least ninety percent methane by volume is in conflict with CPUC's gas specifications that state pipeline natural gas be at least eighty percent methane by volume. While the CPUC requires natural gas utilities to provide the BTU content of customer's purchased gas, there is not a similar requirement for methane content. Further, we understand that the methane content portion of the definition for pipeline natural gas originated with U.S. EPA). U.S. EPA wrote this definition decades ago and it has not been changed to take into account the fact that our nation's domestic natural gas production, including California production, may have lower methane content than ninety percent by volume but a higher overall energy content. We believe that the at least ninety percent methane content in the MRR definition of pipeline natural gas has an insignificant effect on the statewide GHG emission inventory, especially considering that methane has a higher GHG warming potential than the carbon dioxide produced from combustion of natural gas. Thus, lower methane content gas may produce overall lower GHGs than gas with a higher methane content.

SoCalGas and SDG&E urge ARB to make the suggested changes below (shown in red highlight and strikeout) to the definitions in the MRR amendments.

Section 95102(a)(296) "Natural gas" means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include methane, heavier hydrocarbons, and carbon dioxide. Natural gas may be for field use ~~quality (which varies widely)~~ or pipeline ~~quality~~ natural gas. For the purposes of this article, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

Section 95102(a)(338) "Pipeline ~~quality~~ natural gas" means, for the purpose of calculating emissions under this article, natural gas meeting specifications for natural gas ~~having a high heat value~~ as defined by the California Public Utilities Commission (CPUC). ~~greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, and which is at least ninety percent methane by volume, and which is less than five percent carbon dioxide by volume.~~

Section 95102(a)(464) "Transmission pipeline" means a high pressure cross country pipeline transporting sellable ~~quality~~ natural gas from production or natural gas processing to natural gas distribution pressure let-down, metering, regulating stations where the natural gas is typically odorized before delivery to customers.

[F 17.02 – SU]

Response: See response to comment A-4.

K-12. 95102(a) Transmission-Distribution Transfer Station Definition

Comment: The definition for "Transmission-distribution (T-D) transfer station" in §95102(a)(463) is as follows:

"Transmission-distribution (T-D) transfer station" means a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, or a pipeline that falls under the "Hinshaw Exemption" as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717-717 (w)(1994)."

This appears to be the same as the definition for "transmission pipeline" in 40 CFR 98 Subpart W (see 40 CFR §98.238). We believe the intent was to use the definition in 40 CFR 98 Subpart W for Transmission-distribution (T-D) transfer station, which is as follows:

"Transmission-distribution (T-D) transfer station means a metering-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline."

If this is not the case, please explain or provide the correct definition.
[F 17.03a – SU]

Response: ARB staff agrees with the comment, and notes that the change proposed by the commenter was already made in the 45-day proposed language (see section 95102(a)(473).

§95103 – Greenhouse Gas Reporting Requirements

K-13. Effective Date for New Requirements

Comment: MSCG strongly believes that any changes or clarifications to the regulations should have prospective application only. To do otherwise would burden existing and past transactions with unexpected costs, despite informed, good faith intentions to transact on a basis in full recognition of and compliance with the regulations applicable at the time of the transaction. For that reason, MSCG strongly supports the proposed

Modification to Section 95103(h)(8) that adds clarification that new rules and/or clarifications relating to reporting of specified source power will not be effective until January 1, 2014, and thus, transactions entered into prior to January 1, 2014 (even for delivery in 2014) shall be governed by the regulations currently in effect.
[F 11.03 – MSCG]

Response: ARB staff appreciates the support of the commenter regarding the language added to section 95103(h)(8), and agrees that this language provided additional clarity. However, ARB staff disagrees with the commenter's interpretation of the changes made to section 95103(h)(8) because that language does not state that transactions entered into prior to January 1, 2014 would continue with previously in effect regulatory language when reporting 2014 and later years' data. With respect to reporting of 2014 and later years' data and private entity contracts, see response to comment A-30.

K-14. 95103(k)(11). Meter Calibration for Product Meters

Comment: WSPA is also very concerned by the very late staff revision (proposed edits to the 45-day regulation changes were not seen until the morning of the Board Hearing on October 24) that proposes to remove the flexibility ARB had provided facilities in the 2012 edits and the December 2012 Guidance on demonstrating accuracy. By removing the ability to use 95103(k)(11) and imposing 95113(l)(3)(E) for product meters, ARB has proposed a major change that can affect operations without improving measurement accuracy. It is a fact that all data must be reported to within +/-5%. The removal of 95103(k)(11) and the superimposition of new Section 95113(l)(3)(E) is unjustified, unfounded, and does nothing to improve the overall accuracy of emissions or product measurement. In fact, ARB has not provided any information supporting the basis for either of these proposed requirements.

Recommendation: Reinstate Section 95103(k)(11) for product meters and delete section 95113(l)(3)(E). See also our comments on Section 95113 below (p. 5 and p. 6).
[F 10.02 – WSPA]

Response: ARB staff notes that the changes referred to by the commenter were released for a greater than 15-day comment period, to which the commenter is responding. ARB staff declines to make the suggested changes to sections 95103(k)(11) and 95113(l)(3)(E) because ARB staff believes there is enough regulatory flexibility included in sections 95103(k)(1)-(10) to meet the measurement accuracy requirements without section 95103(k)(11). Additionally, see response to comment A-39.

K-15. 95103(k) Measurement Accuracy Requirement

Comment: SDG&E and SoCalGas find some of the field accuracy assessment requirements in §95103(k)(6) excessive when applied to natural gas utilities. As regulated California utilities, SoCalGas and SDG&E have adhered for decades to strict

CPUC measurement standards with more stringent accuracy intervals than those in the MRR. Based on our gas standards covering field meter accuracy tests that assure compliance with CPUC orders, and an audit services department that evaluates internal controls including review of system-wide gas measurement records, we believe additional exemptions should be afforded to California's regulated utilities. Specifically, the requirement [95103(k)(6)(A)(1)(b)] to photograph both sides of the primary element (such as an orifice plate) of pressure differential devices is unnecessary. We request this requirement be eliminated for measurement flow devices operated and maintained by natural gas utilities. [F 17.03b – SU]

Response: See response to comment A-38.

K-16. 95103(h). Guidance for 2014 Emulsion Reporting

Comment: Upstream facilities impacted by the proposed definition of emulsion (from an offshore platform) will have to begin complying with the additional measurement and reporting requirements associated with this volume starting in 2014, through the use of flash testing. A rule finalized by the end of 2013 does not allow impacted facilities sufficient time to evaluate and make, if needed, infrastructure changes necessary to comply with the newly-applicable flash test requirements. In such situations, engineering calculations and other approved methods would be an appropriate substitute for flash testing in the interim.

Guidance Language: Allow facilities which are newly subject to the emulsion testing and reporting requirements as a result of the proposed regulation changes, to use Best Available Methods for 2014 and for such a time as reasonably necessary to complete infrastructure changes. [F 10.22 – WSPA]

Response: See response to comment A-32.

L. Subarticles 1, 2. General Content, Reporting Requirements, and Electric Power Entities, and Electricity Generation (§95104- 95112)

§95104 – Emissions Data Report Content and Mechanism

L-1. Criteria Pollutant Reporting Should be Removed

Comment: The 15-Day Changes properly remove requirements for reporting of criteria pollutants. The previously proposed section 95104(e) (*Increase in Facility Criteria Pollutant and Toxic Air Contaminant Emissions*), would require reporting entities to include information in their emissions data report that also addresses (1) whether a change in the facility's operations or status potentially resulted in an increase in emissions of criteria pollutants or toxic air contaminants in relation to the previous data year, (2) the reasons for the change, and (3) a narrative description of the reasons for the changes. The Modified Text properly strikes the requirement to submit information regarding criteria pollutants because despite the ISOR's position that this information is needed to support CARB's "*adaptive management monitoring, review, and analysis*" and will be used by CARB to "*assess the potential localized air quality impacts that may result from the Cap-and-Trade program,*" tracking criteria pollutants is outside the scope of the MRR's enabling legislation. As originally proposed, the requirement to report data associated with criteria pollutants exceeds the scope of the mandate set forth in Health and Safety Code section 38530 to implement regulations to require "*reporting and verification of statewide greenhouse gas emissions and to monitor and enforce compliance with this program*." The information regarding criteria pollutants does not fall within the ambit of "greenhouse gas emissions" to be reported and verified under the enabling legislation, and should, therefore, not be included within the provisions of the MRR.

In addition to being outside the scope of the AB32 reporting mandate, as contemplated, the requirement also would have imposed additional burdens on reporting entities and provides no new information to CARB, as much of the desired information regarding criteria pollutants to the local air districts, sometimes as frequently as quarterly. CARB, therefore, already has access to the information being sought to assess localized impacts and monitor its adaptive management program.

M-S-R supports the revisions set forth in the 15-Day Changes that strike the references to criteria pollutants and supports the exclusion of section 95104(e) from the verification requirements under the Regulation. However, M-S-R cautions that the Board should only adopt additional reporting requirements once their necessity has been demonstrated. As proposed in the Modified Text, section 95104(e) now requires reporting entities to provide the following *new* information to CARB, each year: (1) whether a change in the facility's operations or status potentially resulted in an increase or decrease of more than 5% in emissions of greenhouse gas emissions in relation to the previous data year, (2) the reasons for the change, and (3) a narrative description of the reasons for the changes. Before adopting additional reporting requirements under the Regulation, M-S-R urges CARB to demonstrate the need for the additional data, and to ensure that the added value of the newly required information outweighs the administrative burden on reporting entities. If it is still determined that CARB must require this extra reporting requirement, all of the information provided pursuant to section 95104(e) is properly expressly excluded from the Regulation's verification requirement. [F 09.03 – MSR]

Response: See response to comment A-42a-o. ARB staff believes these requirements are necessary to support ARB's Cap-and-Trade adaptive management efforts.

L-2. Supports Removal of Criteria Pollutants and Toxics Requirements
Comment: Air Products supports the narrowing of the requirements for reporting the nature and reasons for year-on-year GHG emissions changes and recommends explicitly stated protection of such disclosure as Confidential Business Information.

Air Products supports the elimination of the proposed reporting obligation related to year-on-year changes in criteria pollutants and air toxic contaminants, as these pollutant emissions are not necessarily directly linked to greenhouse gas emissions variability. However, the proposed replacement of this requirement with a new requirement to disclose underlying reasons for year-on-year changes in GHG emissions retains many of our concerns related to protection of confidential business information (CBI).

First, it is not clear why this disclosure is warranted, as it does not inform the state's overall emission inventory nor facilitate compliance under the cap and trade program. Second, the information sought provides insight to competitors and customers about commercial (production volume changes) and operational (process and/or raw material changes, efficiency changes, etc.), information that is commonly accepted as CBI. We are concerned that, due to the bases of the information sought, some parties could interpret such a disclosure to be considered "emission data" and therefore not eligible under California regulation for a claim of public disclosure protection as confidential.

Air Products strongly recommends that ARB eliminate the entire §95104(f) in the proposed rule. If ARB is not otherwise persuaded to eliminate this reporting requirement, they should, at a minimum, explicitly state the inherent confidentiality of such disclosures and the agencies intent to automatically treat such information as confidential and provide the full protection allowed under California law.
[F 13.02 – APC]

Response: See response to comment L-6 [F 12.03]. ARB staff agrees that the information collected would be treated as confidential consistent with California law, but declines to remove section 95104(f). In order to facilitate confidentiality designations, pursuant to section 95106 of the MRR, Cal e-GGRT has a location where users can enter in a list of what they deem to be confidential. As explained in response to comment A-26, the California Public Records Act has additional provisions that protect a company's confidential information that has been submitted to the state.

L-3. CARB SHOULD REVISE SECTION 95104(f)

Comment: Section 95104(f) would represent a significant new burden for every facility operator where the facility experienced a 5 percent (%) change in GHG emissions from the previous year. In the electricity generation sector, a 5% difference (either increase or decrease) in GHG emissions reflects a small change in output that could literally occur every year. Indeed, data reported to CARB in 2012 indicates that the in-state electricity generation source category collectively had emissions of 30,732,215 metric tons of carbon dioxide-equivalent per year ("$MTCO_2e$/year") in 2011 and 41,610,182 $MTCO_2e$/year in 2012, representing a 35% increase in GHG emissions year-over-year for the sector as a whole.

If a 5% change in GHG emissions occurs, the facility operator must specify whether the change was caused by: "(A) Change in production; (B) Changes in facility operations in order to comply with: 1. The cap-and-trade regulation; 2. Other air pollution regulations;

3. Other regulations, not related to air pollution or greenhouse gases; (C) Changes in efficiency due to: 1. Process or material changes; 2. The addition of control equipment; 3. Other efficiency measures; (D) Other"[13] and provide a "narrative description of how each reason identified [] caused the increase or decrease in emissions."[14] The sheer breadth of the potential reasons that CARB provides in section 95104(f)(2) suggests that identifying the cause of any observed emissions change is no simple task. Yet, among the options provided, none is well-suited to changes in emissions due solely to increased or reduced dispatch of a particular electric generating facility or deliveries of imported power from a particular source.

Consider the 35% increase in GHG emissions from in-state electricity generation from 2011 to 2012. CARB identifies the increase in *total* state-wide emissions as resulting from "California electricity generation using natural gas as a fuel" (i.e., increased dispatch of natural gas-fired power plants). In turn, "[t]he majority of this additional natural gas electricity generation is due to a decrease in available hydroelectric generation for 2012 and a reduction in nuclear generated power from the closure of the San Onofre Nuclear Generating Station."

However, for any given natural gas-fired power plant, the increase in GHG emissions is due simply to the fact that the plant was called to dispatch more in 2012 than in 2011. If section 95104(f) were in effect for the 2012 reporting year, it is unclear how an individual power plant operator would account for this change in its emissions data report. Of the choices presented, the operator might select "[c]hange in production" (section 95104(f)(2)(A)), because "production" of electricity increased and therefore "change[d]". On the other hand, the operator might select "[o]ther" (section 95104(f)(2)(D)), because no change in the method of operation occurred and none of the other options applies. Asking the facility operator to then opine on how one or more of these reasons caused the increase in a "narrative description" only further confounds the exercise. An individual facility operator cannot be expected to deduce the intricate economic, factual and regulatory reasons behind every 5% change in an electric generating facility's GHG emissions.

The same holds true with respect to electricity importers, who may experience greater than 5% increases or decreases in their GHG emissions between years due to changes in the volume of imported electricity or the source of such electricity, i.e., whether it obtains power from one specified source/asset-controlling supplier or another or from an unspecified source. In neither case should the reporting entity be expected to provide a detailed analysis of the multiple factors that resulted in dispatch of, or delivery from, one facility over another or at different levels than in the previous year.

Should CARB dispute the facility operator's identified basis for the change or deem the accompanying "narrative description" inaccurate or inadequate, CARB could pursue an enforcement action against the reporting entity. Under the MRR, "[p]enalties may be assessed for any violation of this article pursuant to Health and Safety Code section 38580."Additionally, "[e]ach day or portion thereof that any report required by this article remains unsubmitted, is submitted late, or contains *information that is incomplete or inaccurate* is a single, separate violation." In turn, under Health and Safety Code section

38580, any person violating the MRR is subject to the general Health & Safety Code penalty provisions that apply to violations of air quality requirements (e.g., Health & Safety Code §§ 42400, 43025). Given how vague the "narrative description" requirement is, it is unclear what degree of detail is necessary to fulfill section 95104(f) and whether, in attempting to explain the multiple factors that might have arguably influenced demand for their products, reporting entities should err on the side of 1,000 words when 10 would suffice.

The proposal also presents significant questions with respect to protection of confidential business information under the California Public Records Act ("CPRA"). While the CPRA affords protections for "trade secrets", it also includes an express exception for "all air pollution emission data, including those emission data which constitute trade secrets". Gov't Code § 6245.7(e). A reporting entity might justifiably be concerned that competitors operating under the guise of public interest will make the claim that the narrative explanations included in an emissions data report are more correctly categorized as "emissions data", than protectable "[d]ata used to calculate emissions data". *Id*. With so few parameters and limited guidance on what reporting entities must include in their narrative descriptions, a reporting entity may feel compelled, at risk of penalty, to describe innumerable factors that, if disclosed, could damage its competitive position, such as the terms of new contracts for the sale of electricity. While the MRR allows entities to designate certain information submitted in an emissions data report as "confidential" (MRR § 95106(b)), CARB can provide no guarantee that the limits of protection afforded by the MRR and CPRA will not be tested by those seeking a competitive advantage or that a judge will not decide that the purported public interest in understanding the basis for any increase in a reporting entity's emissions outweighs any protectable interest in statements in its emissions data report.

Without diminishing the importance of the goals of the AMP, we question the value of information on observed changes in GHG emissions to CARB's assessment of localized air quality impacts, which is the only conceivable basis for section 95104(f). Both CARB and members of the public can readily discern whether a facility experiences a 5% change in its GHG emissions by direct reference to the annual MRR emissions data reports. Additionally, there is a wealth of existing data that CARB can use to determine whether TAC or criteria pollutant emissions are increasing at facilities subject to the MRR. CARB should utilize these data and then coordinate with local air districts to obtain additional information directly pertinent to increases in localized air pollutants, before imposing a burdensome reporting requirement on all reporting entities as part of the MRR.

In sum, we do not question the importance of the AMP's goals, but whether CARB's proposal amounts to a reasonable means in furtherance of these goals. We therefore recommend that CARB include an additional option specifically tailored to operators of electric generating facilities and importers of electricity, allowing them to identify changes in the dispatch level of their facilities or the volume or source of imports as the basis for any observed increase or decrease, without requiring any further explanation or detail. We also recommend that CARB eliminate the "narrative description" requirement altogether due to the lack of any clear criteria on what level of detail is necessary to fulfill this requirement and the burden imposed on individual facility operators to explain the many factors affecting dispatch of electric generating units and deliveries of imported power. Accordingly, Calpine proposes the following revisions to section 95104(f), with additions shown in underlined text and deletions shown in strikethrough text:

§ 95104. Emissions Data Report Contents and Mechanism.

(f) *Increases and Decreases in Facility Emissions*. The operator of a facility identified in section 95101(a)(1)(A)-(B) that is subject to the cap-and-trade regulation must include the following information in the emissions data report:

(1) Whether a change in the facility's operations or status resulted in an increase or decrease of more than five percent in emissions of greenhouse gases in relation to the previous data year.

(2) Specify which of the following reason(s) ~~would be~~ were the cause of the increase or decrease in greenhouse gas emissions:

(A) Change in production;

(B) Changes in facility operations in order to comply with:

1. The cap-and-trade regulation;
2. Other air pollution regulations;
3. Other regulations, not related to air pollution or greenhouse gases;

(C) Changes in efficiency due to:

1. Process or material changes;
2. The addition of control equipment;
3. Other efficiency measures;

(D) For an electric power entity reporting pursuant to section 95111 or the operator of a facility reporting pursuant to section 95112, changes in either the volume or source of electricity imported by such entity or the volume of electricity or thermal energy generated by such facility;

(E) Other.

(3) ~~A narrative description of how each reason identified in section 95104(f)(2) caused the increase or decrease in emissions. Include in this description any changes in your air permit status.~~

~~(4)~~ This section 95104(f) is not subject to the third-party verification requirements of this article.

These proposed revisions to the 15-Day Amendments would provide CARB with adequate screening information concerning observed increases and decreases in GHG, which it could then use to pursue additional information on possible impacts on localized air quality, in furtherance of the goals of the AMP. At the same time, individual facility operators would not be tasked with the potentially impossible task of analyzing the many potential factors that influence demand for electricity and face the risk of penalty, should CARB disagree with the identified reason for the reported change or find the accompanying narrative description to be either inaccurate or inadequate.
[F 15.01 – CPN]

Response: See response to comment L-2 [F 13.02] regarding the administrative burden, confidentiality, and the purpose of section 95104(f) responses. ARB staff declines to make the commenter's changes to section 95104(f). As the commenter states regarding section 95104(f)(2)(D), the changes in volume of production can be reported under this category. ARB staff also notes that electricity importers are likely not subject to this portion of the regulation because section 95104(f) refers to only facilities identified in section 95101(a)(1)(A)-(B). ARB staff understands that large fluctuations may occur on a year over year basis for electricity generation. A valid reason for this shift may not be listed in sections 95104(f)(2)(A)-(C), but the "Other" category can be used. This will allow the facility to explain the reason for the increase or decrease in GHG emissions, and whether it was due to changes in volume of production.

L-4. 95104(e). Reporting of Only Changes to GHG Emissions

Comment: WSPA supports ARB's proposed action to report changes to GHG emissions. [F 10.11 – WSPA]

Response: ARB staff appreciates the commenter's support of the changes made to section 95104(f).

L-5. 95104. Guidance for Section 95104(d) & 95112(a)(5)(C)

Comment: WSPA commented previously in the "discussion draft" regarding need for clarification on proposed revisions to Sections 95104(d) and 95112(a) (5) (C) respectively.

ARB added amendments in Section 95104(d)(4) requiring that if a facility's boundary includes more than one cogeneration system, boiler or steam generator and each system produces thermal energy for different end users or on-site processes and operations, the facility will be required to report the disposition of generated thermal energy by unit/system or by group of units with the same dispositions and by the type of thermal energy product provided.

Based on WSPA's understanding, the requirement for an operator to report the disposition of generated thermal energy by "unit/system or by group of units" is defined as a group of units (e.g. cogeneration turbines) that are located at one facility location of which the reporting of thermal energy that goes to a single third party can be reported as a single unit. For example, if there is a cogeneration unit with 3 gas turbines and the generated thermal energy is sold to a single third party operator (i.e., a utility) the data from all three turbines can be combined and reported as single data.

In addition to referencing "particular end-user" ARB also requires the reporting of the disposition of thermal energy for "on-site industrial processes".

Guidance Language: ARB should clarify in a Guidance document that, for reporting of thermal energy for "on-site industrial processes", the total amount of thermal energy can be reported in total if the total thermal energy is used by the same facility. For example, if a refinery operates a cogeneration unit on-site and the thermal energy produced by the cogeneration unit is used by the same on-site refinery, the refinery can just report the total amount of thermal energy that is used within its facility boundary.

In addition, ARB should provide workshops/training to reporters to ensure there is a clear understanding of both the regulatory reporting requirements including the Cal-eGGRT tool for reporting the disposition of thermal energy. [F 10.18 – WSPA]

<u>Response</u>: See response to comment A-43 regarding the purpose of the additions to sections 95104(d)(4) and 95112(a)(5)(C). ARB staff is committed to ensuring the reporting requirements are implemented correctly. If necessary, guidance will be issued on this topic to resolve any confusion regarding reporting the generation unit configurations.

L-6. 95104(f). <u>Section 95104(F) Is Improved, but Remains Burdensome and Should Be Deleted.</u>

<u>Comment</u>: Proposed section 95104(f) (previously section 95104(e) in the September Amendments) requires operators of certain facilities, including power plants, to:

• report whether a change in the facility's operations or status potentially resulted in an increase or decrease of more than five percent in emissions of greenhouse gases (previously criteria pollutants or toxic air contaminants) in the previous data year;

• specify the cause of the increase, choosing from a list of reasons (including changes to production, operations, efficiency, or other); and

• describe how each listed change caused the increase.

Section 95104(f)(4) provides that this provision is not subject to third-party verification.

SCPPA appreciates the changes to this provision from the September Amendments, particularly the change from criteria pollutants and toxic air contaminants to greenhouse gases and the deletion of the verification requirements. Greenhouse gases are the proper subject of the Regulation under Assembly Bill ("AB") 32, specifically, section 38530 of the Health and Safety Code. This section provides that the ARB shall establish "regulations to require the reporting and verification of statewide greenhouse gas emissions." The reporting regulation shall, among other things, "Require the monitoring and annual reporting of greenhouse gas emissions from greenhouse gas emission sources."

Despite these improvements, complying with section 95104(f) will still be burdensome for covered entities. It will be difficult for reporting entities to determine the causes of any increase or decrease in greenhouse gas emissions – for example, to distinguish how much of the increase was caused by changes in operation to comply with regulations and how much was caused by efficiency changes. It will be time-consuming to write a narrative description of how each identified reason caused the increase or decrease in emissions. Electric sector entities are subject to considerable swings in emissions from year to year due to a host of factors including the availability of hydropower and nuclear energy and successes or delays in establishing new renewable energy plants. Thus, electric sector entities are likely to have to report reasons for changes greater than five percent every year. There is no reference in this section to reporting criteria pollutants and determining the reasons for any increase, and such reports would have been outside the scope of the greenhouse gas reporting regulation as envisaged in AB 32.

It is also unclear how these relatively subjective, unverified (and unverifiable) reports will provide useful information to the ARB.

Rather than including this burdensome and unhelpful provision, the ARB should refer to previous years' greenhouse gas reports under the Regulation to determine whether covered entities have increased or decreased their emissions. In addition, the ARB can access various publicly available reports on air pollutants that facility operators are already required to prepare under other regulations. Section 95104(f) should be deleted. [F 12.03 – SCPPA]

Response: ARB staff appreciates the support of the commenter regarding the modification of section 95104(f), but declines to delete section 95104(f). The commenter states that the requirements of section 95104(f) may be unduly burdensome or unhelpful to ARB staff. The data provided by this section will be used to support the Cap-and-Trade adaptive management program by allowing ARB staff to effectively evaluate not only the amount of increase or decrease (which as the commenter notes, ARB will already be able to do based on reported data), but why facilities in California believe they have a greater than five percent emissions increase or decrease on a year-over-year basis. In crafting this reporting requirement in the reporting tool (Cal e-GGRT), ARB staff will ensure the data entry is streamlined and straightforward. ARB staff is also committed, if necessary, to provide guidance regarding the narrative requirements within section 95104(f).

§95105 – Recordkeeping Requirements

L-7. 95105. Guidance for Section 95105 (c)(7) – Recordkeeping Requirements

Comment: ARB proposes adding in the reference “AGA Report No.3 (2003) Part 2”, as a reference document to be used for orifice plate inspection requirements. WSPA believes that API’s “Fuel Gas Measurement document; API Technical Report 2571; First Edition, March 2011” should also be used as a basis for orifice plate inspections. This API technical report compliments the “AGA Report No. 3(2003)” and “ISO 5167-2 (2003)”, and it provides additional guidance for meters in refinery fuel gas service that ensure compliance with MRR metering requirements. Facilities should be able to use this additional reference especially if it provides more appropriate guidance that is consistent with “AGA Report No.3 (2003) Part 2” and “ISO 5167-2 (2003)”.

Guidance Language: ARB should note that API’s “Fuel Gas Measurement document; API Technical Report 2571; First Edition, March 2011” can be used in conjunction with “AGA Report No.3 (2003) Part 2” and “ISO 5167-2 (2003)”. 13 ARB should also clarify that in the event there is a disagreement with a verifier over an orifice plate inspection based on the referenced fuel measurement documents, the reporter can utilize alternative engineering methods to demonstrate orifice plate accuracy.
[F 10.20 – WSPA]

Response: See response to comment A-44.

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

§95111 – Electric Power Entities

L-8. System Power

Comment:

IEP previously submitted comments on the Proposed Amendments to the Mandatory Reporting Regulation (45-day language).[1] In those comments, IEP supported CARB's proposal to more accurately define the emissions rate for unspecified system power that is imported into California. Currently, the evidence indicates that the default emission rate imputed by CARB for power imported into California from unspecified resources, so-called "unspecified system power," may not be representative of the actual GHG emissions associated with the power imported into California.[2] Accordingly, CARB's original proposal to calculate a specific GHG emissions rate for system power suppliers whose system emissions rate exceeds the default rate was appropriate as a means to ensure more accurate reporting.[3]

Unfortunately, in the most recent 15-day language, CARB deletes this provision [Section 95111(b)(5) in the 45-Day Language] altogether, without providing a counter proposal. IEP is concerned that CARB's unwillingness to include such a proposal will undermine the integrity of the cap-and-trade program, foster resource shuffling, and create an unfair advantage for in-state vs. out-of-state resources. In order to more accurately reflect the carbon content of power that is imported into California, IEP recommends that the CARB re-insert the proposal as described in the 45-day revisions. As an alternative to re-incorporating the previously proposed language, IEP recommends that the CARB insert the following language:

Section 95111(b)(5) ***Updating GHG Emissions Rates Associated with Unspecified Imports.*** **The Executive Officer shall calculate and publish, on the ARB Mandatory Reporting website prior to each calendar year, the emission factor to be applied to imported power that is otherwise not associated with a specific generating resource or resources.**

Retaining the integrity of Section 95111(b)(5), as originally proposed in the 45-day language, is essential in order to demonstrate a commitment to monitoring the actual emission rate(s) of unspecified system power serving California and, thereby, to ensure greater accuracy in the reporting associated with all power serving California; to undermine the incentives for "resource shuffling"; and, prevent so-called leakage of GHG emissions from California's GHG emissions reduction program.

[F 01.01 – IEP]

Response: ARB staff declines to make the proposed change by the commenter. The current unspecified emission factor was developed over a multi-year stakeholder process. Annually updating the unspecified emission factor without stakeholder input is not feasible at this time. Additionally, see response to comments B-6a and B-6n.

L-8. Specified Sources

Comment: NV Energy respectfully submits the following comments on the Air Resources Board ("ARB") Staff proposal to withdraw the September 4, 2013 Amendments to Section 95111(g)(1)(N) of the Mandatory Reporting Regulation ("MRR"). As discussed below, NV Energy is concerned that the ARB staff's requirement for an hour-by-hour comparison of the meter data and e-tags for imports cannot apply to NV Energy because of the multi-state nature of the NV Energy Balancing authority. Section 95111(g)(1)(N) would provide as follows:

> (1) *Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment.* The following information is required:
> ***
>
> (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 ***at the time the power was directly delivered.*** (emphasis added)

The CALPECO/Liberty service territory is located in the Lake Tahoe area. This service territory is operated by CALPECO/Liberty, but is within the NV Energy balancing authority. Since the electricity imports from NV Energy to CALPECO/Liberty do not cross balancing authorities, NV Energy does not tag the power that is delivered from NV Energy to CALPECO/Liberty. Thus, it would not be possible for NV Energy to compare meter generation data with e-tags. In past reporting periods, NV Energy has complied with the MRR by submitting information that renewable sources have generated enough power to account for the renewable power imported to CALPECO/Liberty. We have also transferred to CALPECO the established Renewable Energy Credits for this power. Otherwise, NV Energy has reported the system power mix associated with imports under the CALPECO/Liberty – NV Energy Supply Agreement, which was approved by the California Public Utilities Commission. Given the unique circumstances of the NV Energy balancing authority and contractual relationship with CALPECO/Liberty, NV Energy believes that the information submitted in past reporting periods for imports to CALPECO/Liberty comply with the MRR as proposed to be revised on November 1, 2013. [F 06.01 – NVE]

Response: ARB staff declines to make this proposed change. ARB staff is committed to working with reporting entities to ensure this requirement can be met, recognizing that there are unique situations for certain reporting entities. However, staff believes this requirement is important to ensure the accuracy of the reported data to the mandatory reporting program. Additionally, please see response to comments B-12a and B-12d

L-9. Specified Source Conversion

Comment: TransAlta requests that ARB clarifies whether or not it is permissible to convert an unspecified power transaction conducted via a broker or exchange, into a specified source transaction. [F 04.04 – TA]

Response: It is not permissible to convert an unspecified power transaction conducted via a broker or exchange into a specified source transaction. Such a conversion would not satisfy the requirements for reporting specified power in section 95111, or the definition of “specified source” from section 95102(a).

L-10. ACS Power

Comment: TransAlta appreciates the opportunity to comment on the proposed amendments to the Regulation For The Mandatory Reporting of Greenhouse Gases. Our comments below focus only on the requirements for reporting by electric power entities. TransAlta supports many of the proposed amendments, suggested by staff in the latest draft of regulations sent to the Board, during the October 25th public hearing. Specifically we are encouraged to see two commitments made by staff in the public notice released on October 28th .

These commitments are:
1)That staff, in response to stakeholder comments, intends to issue revised statements in the Final Statement of Reasons to effectively withdraw the seller control interpretation for asset controlling suppliers associated with section 95111(a)(5)(B). This change will help to ensure electric power entities know how to effectively report their purchases of asset controlling supplier power, and;

2)That staff acknowledges in the public notice that amendments were made to section 95111, to ensure consistent reporting with previous reporting years.

The modifications provided by the amendments and clarified by the public notice imply that ACS power, will be considered as a specified source, if the power is directly delivered along a single transmission path which identifies the asset-controlling supplier on the physical path of the NERC e-Tag as the PSE at the first point of receipt. This is consistent with reporting requirements in previous years, and something that TransAlta supports. Though we welcome this change, our interpretation of these regulations differs from what we have heard publically from ARB in previous public statements. Specifically, we previously understood, prior to this release, that to purchase and claim a specified ACS source, the power must be accompanied with a written power contract, which is contingent upon delivery of power from the asset-controlling supplier’s system at the time the transaction is executed. This previous guidance implies that specified source transactions would include bilateral transactions, but exclude ICE trades. In contrast however, this new regulatory language included in the draft reads similar to previous reporting years, in which all ACS sourced power is to be reported separately as a specified source, if delivered appropriately. TransAlta welcomes these new amendments, but would appreciate ARB issuing further guidance on ACS transactions, specifically clarity related to energy supplied by the Bonneville Power Administration, to ensure consistency in the verification across the power market. [F 04.01 – TA]

Response: ARB staff appreciates the support of the proposed 15-day language regarding the revised requirements for electric power entities. For more information on the seller control concept and also to provide clarification to the commenter's confusion on this topic, please see response to comment B-2a. If needed, ARB staff may issue additional guidance on this topic.

L-11. ACS Power

Comment: Regarding the portion of Section 95111(a)(5)(E) that refers to the tagging of ACS Power, we believe that ARB is fundamentally on the right track with the concept of having the ACS be the PSE on the NERC E-tag. However, there is one transaction type that we believe would be universally agreed could be (not necessarily always is) eligible to be a transaction from an ACS and treatable as from a specified source, that nonetheless would be excluded under the proposed wording. When a party purchases a "slice of system" from an ACS, the PSE on the related e-Tag at the point of first receipt is the transmission owner that is moving energy away from the source busbar, not the ACS entity. The ACS entity is the PSE only on the first line of the physical path of the e-Tag, which is the "Source" field, not a Point of Receipt. A literal interpretation of 95111(a)(5)(E) would not permit this type of transaction to be eligible for "specified" treatment. We wish to make clear that we believe this issue is totally separate from discussion of whether or not a seller, ACS or otherwise, should be able to control whether or not a given sale is "specified; the problem will exist even if the seller agrees that the transaction is specified. For that reason, we believe that support for addressing and resolving the problem (if not necessarily for any given proposed solution) will be universal.

One possible solution that occurred to us is:

(E) Tagging ACS Power. To claim power from an asset-controlling supplier, either the asset-controlling supplier must be identified on the physical path of the NERC e-Tag as the PSE at the first point of receipt, or as the PSE on the "source" line. In the case of asset controlling suppliers that are exclusive marketers, then the ACS must be shown as the PSE immediately following the associated generation owner. [F 11.04 – MSCG]

Response: ARB staff declines to make the commenter's change to section 95111(a)(5)(E) regarding the first point of receipt on the NERC e-tag. ARB staff believes the definition is already clear that the source of the power needs to be from the asset-controlling supplier. Further, the "first point of receipt" definition in section 95102(a) indicates that it is the generation source of the power.

L-12. 95111. New Requirements for Specified Source and ACS Transactions Should Apply Only to Transactions Entered Into After January 1, 2014

Comment: A proposed new sentence in section 95103(h)(8) provides that:

The requirement that a seller warrant the sale or resale of specified source power in section 95111(a)(4) and the requirement for reporting of asset controlling supplier power in section 95111(a)(5)(B) are effective starting with the reporting of 2014 data in 2015 and later years.

SCPPA appreciates the clarification that these provisions will not be retroactive back to January 1, 2013. As a general rule, SCPPA does not support the retroactive application of changes to regulations. However, this sentence does not address the issue of current agreements, which may provide for specified source and asset controlling supplier ("ACS") power deliveries for some period of time after the new provisions take effect on January 1, 2014.

The changes to sections 95111(a)(4) and 95111(a)(5)(B) in the September Amendments were significant. Section 95111(a)(4) requires a new warranty for specified source transactions. The change to section 95111(a)(5)(B) results in a requirement for a written power contract that is contingent upon delivery of power from the ACS system that is designated at the time the transaction is executed, according to the definition of "power contract" in section 95102(a)(356). These requirements are not necessarily addressed in current agreements, and in the case of section 95111(a)(5)(B), current agreements cannot even be amended to address this requirement because source specification must be done at the time the agreement is executed. To address this requirement, a whole new contract would need to be entered into, raising a host of potential commercial issues.

Some SCPPA members have long-term power contracts with asset-controlling suppliers that do not specifically designate the source of the power as the ACS's system. However, the power delivered by the ACS does come from its system, as shown by the e-tags. These contracts have been in place for some years. In the 2012 emissions report, this power could be (and was) claimed as ACS power with the relevant ACS emissions factor, due in part to the requirement in current section 95111(a)(5)(B) to report electricity delivered from asset-controlling suppliers as specified and not as unspecified. If the change to section 95111(a)(5)(B) takes effect for all contracts at the start of 2014, as proposed, the power delivered under these existing contracts could not be claimed as ACS power and must be reported as unspecified (using the default emissions factor) in the 2014 data year report and future reports.

For these reasons, the changes to sections 95111(a)(4) and 95111(a)(5)(B) should apply only to transactions entered into after January 1, 2014, when the changes to the Regulation become effective. Going forward, electricity importers would be aware that any new specified source contracts must contain certain warranties and that any new agreements with asset-controlling suppliers must specify the source of the power, and the importers could take steps to include these provisions when negotiating new contracts. This approach would avoid unfairly penalizing those importers with existing contracts that do not happen to meet the new requirements and that were entered into when no such requirements were in place.

SCPPA proposes the following changes to section 95103(h)(8) to address this issue:

> The requirement that a seller warrant the sale or resale of specified source power in section 95111(a)(4) and the requirement for reporting of asset controlling supplier power in section 95111(a)(5)(B) are effective for transactions entered into on or after January 1, 2014~~starting with the reporting of 2014 data in 2015 and later years~~.

[F 12.02 – SCPPA]

Response: ARB staff appreciates the support of the commenter regarding the addition of language to section 95103(h)(8). ARB staff declines to make the edits to section 95111(a)(4). See response to comment A-30 for more information.

L-13a. Seller Control Proposal for Asset Controlling Supplier Power as Either Specified or Unspecified, Section 95111(a)(5)(B)

Comment: Iberdrola Renewables. In the proposed modifications to Section 95111, the California Air Resources Board indicates its intent to withdraw the seller control interpretation for asset controlling suppliers associated with section 95111(a)(5)(B). Iberdrola interprets this withdrawal to mean all power purchased from an asset controlling supplier will be considered Specified Power under the reporting regulation and will be assigned the established emissions profile for the asset controlling supplier for the applicable reporting year.

The purpose of the California cap and trade legislation is to reduce greenhouse gas emissions by establishing an aggregate greenhouse gas allowance budget for covered entities and providing a trading mechanism for approved compliance instruments. The California Mandatory Reporting of Greenhouse Gas Emissions regulation achieves this objective by tracking the emissions profile of all power generated within the state of California as well as power imported into the state, and requiring mitigation of the associated emissions through the procurement of allowances or offsets. CARB's prior version of the reporting regulation would have provided asset controlling suppliers the discretion to designate certain sales as Unspecified Power, resulting in an attribution of the higher, default emissions profile. This artificial designation would assign an inaccurate emissions profile to the system power sold from an asset controlling supplier, inflating the compliance obligation of entities purchasing this power and importing it into the state of California. CARB's proposed withdrawal of the seller control interpretation for asset controlling suppliers is necessary to preserve the integrity of the California cap and trade legislation by ensuring the emissions profile of the power imported into the state of California accurately represents its generation source.

Certain stakeholders have argued that an asset controlling supplier's ability to designate sales as specified or unspecified is no different than the ability of individual resource owners to sell specified or unspecified power. This comparison is inapplicable. Designation as an asset controlling supplier under the California Mandatory Reporting of Greenhouse Gas Emissions regulation establishes a clear distinction between individual resource owners and asset controlling suppliers. This distinction exists

because the annual emissions profile attributed to the asset controlling supplier incorporates **all** energy transactions of the designated entity – emissions associated with generation from each unit in the asset controlling supplier's fleet, electricity purchased wholesale from specified and unspecified sources by the asset controlling supplier, and wholesale electricity sold by the asset controlling supplier. Permitting an asset controlling supplier to arbitrarily designate a sale of power as unspecified is contrary to the calculation of the emissions factor for an asset controlling supplier and would potentially perpetuate increased price premiums for imports into the state of California, at the ultimate expense of California ratepayers.

Iberdrola Renewables strongly supports the California Air Resources Board's decision to remove the seller control interpretation for asset controlling suppliers and reiterates the importance of its removal to ensure importing entities are not improperly penalized through the reporting mechanism and associated compliance obligation. [F 03.01 – IR]

<u>Response:</u> See Responses to comments B-2a and B-2j.

L-13b.Comment:

Withdrawal of seller control of Asset Controlling Suppliers is discriminatory

WPTF is concerned by the explanation provided on page 3 of the "Notice of Public Availability of Modified Text and Availability of Additional Documents" that "staff intends to issue revised statements in the Final Statement of Reasons *to effectively withdraw the seller control interpretation for asset-controlling suppliers* associated with section 95111(a)(5)(B)." As we noted in our comments to the 45 day proposed changes, WPTF supports the principle that the generation owner should control whether electricity sold is specified and strongly believes that it should be applied consistently to all generation owners.

Under the proposed regulatory amendments, a generation owner would have the implicit ability to control whether a bilateral sale is for specified or unspecified power through its contract practices. A generation owner could sell power as unspecified by, for example, not providing a written power contract (as required by the definition) or by not providing a warranty that the power is specified (as required in revised section 95111(g)). In other words, the terms of a bilateral contract determine whether power is specified – not the mere existence of a bilateral contract. In contrast, CARB's proposed change to the FSOR would render any bilateral sales from asset controlling suppliers as specified, regardless of the intent of that asset controlling supplier. For CARB to exclude one specific class of entity, or worse - one specific entity, from the general principle of seller control is both arbitrary and discriminatory.

WPTF notes that if CARB withdraws the seller control interpretation for one or more asset-controlling suppliers, an ACS could simply sell power anonymously through brokers or on the Intercontinental Exchange. CARB's withdrawal of the seller control for asset-controlling suppliers will thus not prevent sale of unspecified power by asset controlling suppliers, but rather force them to make changes in their marketing practices that may result in less efficient outcomes. It would be an inappropriate intervention in the wholesale power market for CARB to restrict asset-controlling suppliers, or for that matter any generation owner, from bilateral power sales that are not 'contingent upon delivery' from that unit/facility or asset-controlling supplier system. Yet, this is what withdrawing seller control would do.

For these reasons, WPTF urges CARB to retain and apply the seller control principle consistently to all resources and entities. CARB should clarify in the FSOR that all generation owners, including asset controlling suppliers, have the implicit ability to control whether power sold bilaterally from their assets is specified or not (e.g. through inclusion in the contract of language requiring and warranting the power to be supplied from a specific unit or ACS system). Given that the seller control principle has only been clearly articulated as of the 2013 regulatory amendments, and the fact that CARB's conflicting guidance on specification of electricity purchases from asset controlling suppliers[2] has created significant uncertainty in the electricity market, the seller control principle should be applied prospectively for contracts executed after December 31, 2013.

If CARB does not maintain and apply the seller control principle consistently to all entities, then it is incumbent upon staff to clearly articulate the basis for its discriminatory treatment and the conditions under which a generation owner, including an asset-controlling supplier, may sell power as unspecified. Understanding these distinctions will be important to both electricity buyers, as well as other entities that may consider applying for ACS status in the future. CARB should also publish the names of current and any future Asset Controlling Suppliers that may sell unspecified power bilaterally, and those that may not.

[F 07.01 – WPTF]

Response: See response to comment B-2a for more information regarding the purpose of removing the seller control concept. ARB staff disagrees with the commenter regarding the bilateral sale of asset-controlling supplier power. As described in response to comment B-2a, ARB staff is not trying to limit the way an asset-controlling supplier does business, but merely ensure fairness around product designation. Further, ARB staff disagrees with the commenter regarding that this change interferes with the wholesale markets. The ability of an asset-controlling supplier to sell power on any market is not limited by the reporting regulation provisions. In the proposed 15-day modifications, changes to section 95103(h)(8) ensures that the new provisions will not be applied retroactively to 2013 data. Lastly, ARB staff will consider, when publishing the ACS emission factors later this year, whether any additional caveats are necessary for use of the factors.

L-14. Classification and Verification of Reported Transactions

Comment: TransAlta requests ARB to make clarifications which explicitly acknowledge that a power trade which occurs when one version of the MRR is in place should be verified under those regulatory requirements, and not the regulations in effect at the time of first delivery, while confirming that no regulations should be applied retroactively. [F 04.02 – TA]

Response: See response to comment A-30.

L-15. Electricity Transaction Reasonable Assurance

Comment: TransAlta requests that ARB clarifies the verification requirements necessary to meet the reasonable level of assurance required for the verification of a specified source transaction. Particularly, TransAlta would like clarification on whether supporting details such as calibration records, maintenance schedules, or information on system controls, must accompany meter data. It is our understanding from ARB public comments, that meter data alone is sufficient to satisfy the regulations, but would appreciate a guidance document to address this issue, to ensure consistency in verification across the industry. [F 04.05 – TA]

Response: During verification services for an electric power entity, the verifier is expected to determine whether there is reasonable assurance that the reported emissions data is accurate. Based on ARB staff's understanding, the meters used for power transactions meet the accuracy requirements outlined in the MRR. For this reason, meter generation data is sufficient to demonstrate accuracy to the verifier.

L-16.Comment:

CARB needs to explain how inconsistencies in regulation will be rectified.

WPTF remains concerned about inconsistencies between various regulatory provisions. For instance, if staff withdraws the seller control explanation for asset controlling suppliers and instead determines that all power purchased bilaterally from BPA will be considered specified, then staff will have created a potential inconsistency with requirements for tagging of ACS power. If an entity has purchase power bilaterally from BPA that power would be considered specified under CARB's approach, but if the entity received delivery that is sourced from a BPA path out purchase, the import would fail the tagging requirement in 95111(a)(5)(E) because BPA would not be listed as the first PSE on the tag. Under this scenario, which regulatory provision takes precedent? WPTF requests that CARB explain how it would resolve cases where regulatory provisions conflict.

[F 07.02 – WPTF]

Response: See response to comment B-5a-c for information regarding path outs. With the removal of the path out provisions from the reporting regulation, ARB staff plans to treat BPA power that would have been classified as a path out in the following manner. Consider 100 MWh of power from BPA with a specified source contract. Upon delivery, 95 MWh are sourced from the BPA balancing area and the other 5 MWh are from a path out. For reporting purposes, the 95 MWh would get the BPA asset-controlling supplier emission factor and the other 5 MWh would get the unspecified emission rate. ARB staff believes this interpretation is consistent with the current requirements in the MRR. In order to claim a specified source, an electric power entity must have a power contract and associated NERC e-tags.

L-17. Meter Generation Data

Comment:

Further guidance is needed on demonstration that power was generated at the time it was directly delivered.

WPTF supports CARBs reinsertion of the phrase "at the time the power was directly delivered" in section 95111(g). However, we understand the concerns raised by other stakeholders that the

requirement to report the lessor of generation or scheduled imports in an hour, in accordance with this regulatory provision, could be unnecessary in certain scenarios or could be implemented in a way that is overly burdensome. We therefore recommend that CARB initiate a stakeholder process with the objective of developing practical guidance on interpretation and implementation of this requirement, including reporting and verification. This additional guidance should clarify when meter data is required to demonstrate that generation occurred at the time of delivery, and any cases where other documentation will be acceptable in lieu of meter data. We note that CARB has already indicated that it will accept Mid-Columbia Hourly Allocation Data for participating hydroelectric resources, in lieu of meter data.

[F 07.03 – WPTF]

Response: See response to comment B-12a. ARB staff plans to work closely with stakeholders so they fully understand the reporting requirements, including providing explanatory guidance regarding the implementation of these metering requirements, if necessary.

L-18. Meter Generation Data

Comment:

1. **The ARB Should Not Withdraw Its Proposed Amendments To Section 95111(g)(1)(N).**

Currently, the MRR requires covered entities to *retain* meter data from specified sources for purposes of verification. However, the reporting tool and ARB guidance seem to require more than just retaining the meter data. TID understands that the ARB may want Electricity Importers to conduct an hour-by-hour comparison between the generating facility meter data and the MWh on the e-tag, and to report specified imports as the lesser of the meter or the MWhs on the e-tags for each hour. TID is concerned that such a comparison could create a significant administrative burden both for the reporting entity and the verifier with respect to conventional, non-RPS resources. Depending on the number of imports involved and the number of e-tags generated in a single day, it could take weeks for staff to complete this comparison. In some cases, e-tags might need to be split, and as a result, it would be difficult for a verifier to recreate the covered entity's analysis. This additional burden would exceed the likely benefit to the ARB as the incremental difference in compliance obligation will be minor. In almost all cases, the metering data will be consistent with the e-tags and any minor improvement in reporting accuracy would be swamped by the potential direct administrative burden on reporting entities and increased verification costs.

The ARB's September 4, 2013 proposal to remove certain language in Section 95111(g)(1)(N) would have addressed these concerns by limiting the hour-by-hour comparison. If the ARB withdraws these revisions, then the ARB should minimize the administrative concerns noted above. As discussed in the next section, there is a need for clear regulatory language and guidance on this issue.

[F 08.01 – TID]

Response: See response to comment B-12h.

L-19. Meter Generation Data

Comment:

2. **The ARB Should Clarify Its Proposal, And Explain How The Change In Staff's Position Will Ensure Consistent Reporting With Previous Years.**

To minimize the potential administrative burden and confusion associated with Section 95111(g)(1)(N), the ARB should consider amendments provided in Attachment A to these comments. These amendments would require reporters to retain meter data and make it accessible to verifiers if questions of overscheduling arise. Reporters would not face new administrative hurdles, but the ARB would nevertheless have a mechanism for improving data accuracy if it so desires. Under this proposal, the verifier (based on ARB direction or if questions of over scheduling arise) could compare meter data to e-tag information for particular resources. If the verifier discovers an inconsistency between e-tag and meter data, the verifier would update the reported information to reflect the lesser of the meter or verification data. To avoid creating an implicit obligation for reporters to make this comparison for all resources, the ARB should clarify that this correction would not constitute a "material misstatement" as that term is defined in the MRR. The possibility of potential material misstatements would render guidance about not having to do the hour-by-hour comparison meaningless.

If despite the minimal improvement in reporting accuracy, the ARB still believes some comparison of meter and e-tag data is necessary, then the ARB should only require this comparison across a longer time horizon. For example, the ARB could minimize the administrative burden discussed above by clarifying that reporters will only be required to compare meter and verification data across an annual or monthly time horizon. TID believes that a comparison of monthly or annual e-tag and meter data would yield substantially similar (albeit minimal) improvements in reporting accuracy as an hourly comparison.

In sum, it is important to provide clear regulatory language and guidance about the ARB's expectation for the use of meter data and the associated verification requirements. TID's two proposals for addressing these concerns are provided in Attachment A to these comments.

ATTACHMENT A

TID Proposed Amendments To Section 95111(g)(1)(N) (noted in bold and underline):

§ 95111. Data Requirements and Calculation Methods for Electric Power Entities

. . .

(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. **Electric Power Entities are not required to make an hour-by-hour comparison of meter generation data and other reported information. The verifier may make such a comparison, and any subsequent correction to an electric power entity's reported information will not constitute a material misstatement.**

Alternatively, the ARB should amend Section 95111(g)(1)(N) as follows:

§ 95111. Data Requirements and Calculation Methods for Electric Power Entities

. . .

(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**, based on a comparison of a full year of meter data against a full year of e-tag data**.

[F 08.02 – TID]

Response: ARB staff disagrees with the commenter on the two suggested versions of changes to section 95111(g)(1)(N). The first suggested change in Attachment A would eliminate the need for meter generation at the hour-by-hour level, which is inconsistent with the current reporting requirements. Their second sentence on verification is redundant with the first sentence and would essentially eliminate any verification of this provision. The second suggested language in Attachment A does not work because a verifier would be comparing annual meter data against hourly e-tags. With this approach, discrepancies are likely and may not result in correct verification. ARB staff notes that the requirement is for the entity to retain this data for verification purposes, not to include in it its emissions data report. Additionally, see response to comment B-12h regarding administrative burden.

L-20. Meter Generation Data

Comment:

3. **The ARB's November 1, 2013 Notice Incorrectly Asserts That Withdrawal Of Section 95111(g)(1)(N) Will Ensure Consistency With Reporting In Previous Years and Reporter Understanding.**

In the November 1st Notice, the ARB states that by withdrawing amendments to Section 95111(g)(1)(N) (and other amendments to Section 95111), the ARB will ensure consistent reporting with previous reporting years and not create new questions of how to report.[2] TID disagrees that the "withdrawal" of Section 95111(g)(1)(N) achieves "reporter understanding." The metering requirements in Section 95111(g)(1)(N) are not clearly understood by reporting entities. To ensure better stakeholder understanding, the ARB should make this a main topic in guidance document(s) and training webinars in early 2014 so that stakeholders can all gain a clear, consistent understanding of the inherent intricacies between Renewable Portfolio Standard ("RPS") and Greenhouse Gas

("GHG") policies. The ARB should also consider TID's proposed Amendments presented in Attachment A to these comments.

[F 08.03 – TID]

Response: See responses to comments B-12h and L-21.

L-21. 95111. Hourly Meter Data for Specified Source Imports and the RPS Adjustment Should Not Be Required

Comment: Section 95111(g)(1)(N) of the Regulation sets out information requirements, for verification purposes, for specified sources and eligible renewable energy resources that are counted towards the RPS Adjustment. In the September Amendments, the phrase "at the time the power was directly delivered" at the end of section 95111(g)(1)(N) was deleted. In the proposed amendments released on October 28, 2013, this phrase was reinstated.

However, requiring hourly meter generation data is problematic for several reasons.

A. Reporting entities may not have access to this data.

First, this data may not be available to the reporting entity. Some existing contracts for specified source electricity do not contain provisions allowing the purchaser access to the hourly meter data. These entities would be required to renegotiate their contracts to include a provision for the supplier to provide meter data. Suppliers may be unwilling to do this without recompense.

B. “Lesser of” hourly comparison process is time-consuming and does not produce a significant difference.

Second, and more troublingly, ARB staff indicated in teleconferences with stakeholders that the purpose of including this phrase is not merely to change the information that must be retained for verification purposes, but to change the reporting requirements. SCPPA understands that electricity importers would be required to compare, on an hourly basis, the meter data against the e-tags for the relevant imports and to claim the lesser of the two values as specified, with the remainder being reported as unspecified power with default emissions.

SCPPA understands that some stakeholders, e.g., Shell, have already adopted this hourly meter and e-tag data comparison process and have not found it particularly troublesome. However, the ARB should not assume that this will be the case for all electricity importers. Certain entities have relatively simple electricity imports so the calculations involved would be straightforward. This is not true for all of the SCPPA members. For example, the share of facility output that some SCPPA members receive may vary from hour to hour; there may be time zone differences to take into account when aligning the hourly meter data with the e-tag data for comparison; and power belonging to multiple reporting entities may be combined and imported on a single e-tag, making it difficult to compare hourly data for an individual entity. For these reasons, obtaining, preparing, and aligning the hourly meter and e-tag data would be a very time-consuming process for some SCPPA members, as the Los Angeles Department of Water and Power (“LADWP”) has shown in correspondence with ARB staff. Additionally, during the verification process the independent verifier would require time to determine with reasonable assurance whether the result of the “lesser of” hourly comparison process is accurate.

The usefulness of this labor-intensive process is questionable. The reports under the Regulation are annual, so accuracy on an hourly basis should not matter, provided that the annual figures provided in the report are accurate. Reported annual imports can be verified using the reporting entity’s share of the generating facility’s annual generation meter data.

Furthermore, LADWP’s sample showed that the result of the “lesser of” hourly comparison process is very close to the sum of the megawatt hours on the e-tags, and the difference is substantially less than the five percent accuracy requirement in the Regulation. The conclusions to be drawn from the LADWP sample are that performing an hour-by-hour comparison would not make a significant difference in the reported emissions and is neither necessary nor effective in addressing any perceived over-accounting of low-emission generation. C. “Lesser of” hourly comparison process is inconsistent with existing requirements in the regulations.

Finally, the “lesser of” hourly matching and comparison process is not required by the plain words of the Regulation (even with the proposed amendments) and, worse yet, would be inconsistent with existing, unchanged provisions of the Regulation as well as with the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms regulation (“Cap and Trade Regulation”).

Section 95111(g)(1)(N) of the Regulation provides as follows, with the proposed amendment underlined:

> (1) Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment. The following information is required:
>
> (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 <u>at the time the power was directly delivered.</u>

This provision does not contain any reference to comparing meter data against delivered power (e-tags) and claiming only the lesser of the two amounts. On the contrary, this provision is “for verification purposes” only and does not on its face contain any instructions as to how the data is to be used in generating annual emission reports. .

The provisions that set out how specified source imports and the RPS Adjustment are to be calculated and reported are sections 95111(b)(2) for power from specified sources, (b)(3) for power from asset-controlling suppliers,5

The definition of “specified source” in section 95102(a) includes asset-controlling suppliers. However, it is unclear whether, or how, section 95111(g) applies to power from asset-controlling suppliers. Section 95111(g) may need to be amended to clarify that it does not apply to power from asset-controlling suppliers. and (b)(5) for the RPS Adjustment. For power from both specified sources and asset-controlling suppliers, the formula for calculating the relevant emissions refers to “Megawatt-hours of specified electricity deliveries” (emphasis added). The formula for the RPS Adjustment refers to the “Sum of MWh generated by each eligible renewable energy resource” (emphasis added). The Cap and Trade Regulation contains similar provisions in sections 95852(b)(3) and (4).

In neither the Regulation nor the Cap and Trade Regulation is there any requirement to claim the lesser of the hourly meter data or the delivered electricity for specified sources and the RPS Adjustment. Therefore, any guidance the ARB issues that sets out the “lesser of” hourly comparison process mentioned by ARB staff in teleconferences would be inconsistent with both the Regulation and the Cap and Trade Regulation.

D. The phrase should be removed, or if it must remain, entities should be able to satisfy this requirement by merely retaining the meter data.

For the reasons discussed above, the phrase “at the time the power was directly delivered” should be deleted from section 95111(g)(1)(N) of the Regulation.

If it is not possible to revise the Regulation at this stage, the ARB should:

• clarify that electricity importers can satisfy the requirements of section 95111(g)(1)(N) by keeping records, for verification purposes, of hourly meter data;

• allow electricity importers to continue to rely on the existing provisions of section 95111(b) when reporting the RPS Adjustment and power from specified sources and asset-controlling suppliers; and

• not require electricity importers to undertake the burdensome and unnecessary “lesser of” hourly comparison process.

[F 12.04 – SCPPA]

Response: See responses to comments B-12a, B-12d and B-12j regarding the data access, the lesser of the hour reporting requirements, the overall report accuracy benefits, and the regulatory justification. ARB staff is committed to working with stakeholders to develop a method that streamline the provisions to ensure the requirements are met. During this time, ARB staff can work through specific issues such as time zone issues and multiple entities on a single e-tag. ARB staff notes that the requirement is for the entity to retain this data for verification purposes, not to include in it its emissions data report. See also response to comment B-12h.

L-22. Verification of Generation Should Not Have to Include Verification that Power was Generated at the Time the Power was Directly Delivered

Comment: The Regulation should not include a provision requiring verification of data for transactions “at the time the power was directly delivered.” When CARB first released the proposed amendments to the Regulation, language in section 95111(g)(1)(N) requiring reporting entities to maintain meter generation data that documents that the power claimed by the reporting entity was generated by the facility or unit “*at the time the power was directly delivered*” was stricken. In the 15-Day Changes, “*at the time the power was directly delivered*” has been reinserted into the Regulation. As more fully addressed in M-S-R’s October 23 comments, and in the detailed comments provided by the Los Angeles Department of Water and Power (LADWP),[3] an hour-by-hour comparison of meter and e-tag data for all specified imports (including non-renewable resources, since subsection (g) does not apply solely to renewable resources) would be a significant labor burden for reporting entities, such as the members of M-S-R. This requirement would encompass considerable amounts of information that would need to be collected and reported to CARB, and which would be subject to verification under the Regulation, both of which result in increased compliance costs for reporting entities. Not only is this requirement costly, it is unnecessary for purposes of meeting the requirements of the MRR for annual emissions reporting. As the section itself states, CARB desires to collect the information “for verification purposes.” Verification of hourly deliveries is irrelevant to an annual emissions report.

Despite assertions to the contrary, this exercise is labor intensive. In addition to written comments on this topic, during the October 25 Board meeting, M-S-R and several other stakeholders expressed their concerns to the Board orally, especially with regard to the implications of the staffing and administrative burdens associated with the additional tracking and reporting. In response, other stakeholders opined that they did not "believe" that the requirement would be unduly burdensome for M-S-R and similarly situated POUs. With all due respect to other stakeholders, their understanding of the magnitude of the burden on M-S-R and other POUs is limited and incomplete. Additionally, as more fully described in the comments submitted by LADWP, the additional cost associated with providing this information is not commensurate with any added accuracy in the information already provided to CARB.

CARB staff acknowledged the concerns raised by M-S-R and similarly situated stakeholders, and advised the Board that staff would work with stakeholders on Regulatory Guidance documents that will assist in the implementation of the requirements. M-S-R appreciates staff's recognition of the concerns. However, while regulatory guidance documents that provide clarification and proposed approaches for addressing the mandate are certainly helpful in an advisory capacity, such documents *are not* legally binding, and therefore, do not have the same force and effect as revisions to the Regulation itself. Accordingly, while M-S-R appreciates staff's efforts to work with affected stakeholders on this issue, the best way to do so is through regulatory amendments and not guidance. With that said, should the Board determine not to retain the amendments first proposed in the 45-Day changes and proceed with retaining the hourly-data requirement, M-S-R looks forward to working with staff on development of the Regulatory Guidance language. [F 09.01 – MSR]

<u>Response:</u> See response to comments B-12-h and B-12j for responses related to the requirements of section 95111(g)(1)(N), responses to LADWP comments, administrative burden, and guidance. For clarification, ARB staff notes that the requirement is to collect the information for purposes of verification, not to actually report the data to ARB.

L-23. <u>References to System Power are Properly Removed</u>

<u>Comment:</u> The Modified Text strikes what would have been new language in sections 95111(a)(12) and 95111(b)(5), and the associated references to system power in sections 95111(g) and 95111(g)(6). M-S-R supports this change. As originally proposed, sections 95111(a)(12) and 95111(b)(5) would have imposed "*system power emission factor rates*," that would be determined by CARB. Purchasers of system power with a carbon content above the default emission factor (DEF) would use a new "system power emission factor calculated by ARB," instead of the lower DEF for unspecified power. This approach was intended to "more accurately reflect the carbon content of the system power, than the use of the [DEF] for unspecified electricity imports." However, as noted in M-S-R's October 23 comments, and in the written and oral comments provided by several stakeholders at the October 25 Board meeting, the concept is too incomplete for inclusion in the Regulation, and fraught with a number of uncertainties,

including a clear proposal for how "systems" would be determined and to whom the requirement would apply. The proposed language was also problematic in that it would have resulted in the provision of inaccurate information regarding the state's true emissions level, as only systems with emissions determined to be higher than the DEF would be assigned a new emissions factor. Ostensibly, systems with lower emissions would still be subject to the current DEF, which would artificially inflate the overall GHG emissions figures for imported electricity.

M-S-R supports the proposed revisions set forth in the Modified Text which would strike the new provisions regarding system power and urges the Board to support the revisions set forth in the 15-Day Changes relevant to sections 95111(a)(12) and 95111(b)(5). [F 09.02 – MSR]

Response: ARB staff appreciates the commenter's support for the revisions. See also response to comment B-6a.

L-24. Path-Out Language Removal

Comment: MSCG strongly supports the proposed removal of the language in Section 95111(a)(5)(E) regarding the exemption of "path outs". As argued in more detail in our comments to the initial Proposed Amendments, we believe the "path out" exemption is not consistent with the underlying concept of an Asset Controlling Supplier (ACS), and indeed, could facilitate resource shuffling. For those reasons, elimination of the "path out" exemption is necessary for the protection of the environmental integrity of the program. [F 11.01 – MSCG]

Response: ARB staff appreciates the commenter's support regarding the removal of the path out language.

L-25. 95111 Removal of Path Outs from BPA System Definition

Comment: Over the past year BPA has had countless conference calls and emails with CARB staff to explain what resources are part of BPA's system under federal law. One area of particular focus in these discussions was the utility standard practice of "pathing out" surplus power procured in the market from time to time. BPA explained that all power BPA purchases is, under federal law, a part of BPA's federal system. If at some later time BPA no longer needs a market purchase because of changes in demand or system conditions, then BPA sometimes resells the surplus purchased power and combines the purchase and sale transaction into a single schedule and NERC e-tag resulting in a "pathout." "Pathouts" are a common industry scheduling practice not unique to BPA.

CARB originally accepted BPA's explanation and legal analysis that "pathed out" power is part of BPA's system. As a result, CARB included language regarding pathouts in section 95111(a)(5)(E) entitled "Tagging ACS Power." However, in the final round of changes leading up to the October 24-25 Board meeting CARB removed this language so that it now reads:

> (E) *Tagging ACS Power*. To claim power from an asset-controlling supplier, the asset-controlling supplier must be identified on the physical path of the NERC e-Tag as the PSE at the first point of receipt, or in the case of asset controlling suppliers that are exclusive marketers, as the PSE immediately following the associated generation owner, ~~with the exception of path outs. Path outs are excess power, originally procured as part of a U.S. federal mandate to serve the operational or reliability needs of a U.S. federal system but which are no longer required due to changes in demand or system conditions.~~

This is a significant deletion because it means that CARB has, for purposes of its regulations, declined to recognize pathouts as a part of BPA's system. BPA wishes to point out that this may result in situations where a buyer purchases from BPA in a bilateral transaction (which, as explained in points #1-2 above, CARB would ordinarily construe as specified and the buyer may think is specified) but will end up being unspecified because, when the power is scheduled each day, some of it may be supplied via a pathout. Thus, the buyer and CARB will need to construe the transaction to be unspecified because BPA does not show up on the e-tag as the original source of the power.

In short, CARB needs to be aware that not all bilateral purchases with BPA will result in a NERC e-Tag that identifies "BPA" as the PSE at the first point of receipt on the physical path. Section 95111(a)(5)(E) will not take this into account if CARB makes the change proposed above in double strikeout lines. [F 16.03 – BPA]

Response: ARB staff is aware of the implications of removing the path out language. Additionally, see response to comment L-16.

L-26. Seller Control

Comment: MSCG strongly supports the clarification ARB staff indicated is forthcoming in its October 28th "Notice of Public Availability of Modified Text and Availability of Additional Documents". Specifically, MSCG is pleased to read that ARB, in response to stakeholder comments. "…*intends to issue revised statements in the Final Statement of Reasons to effectively withdraw the seller control interpretation for asset controlling suppliers with section 95111(a)(5)(B). This change is needed to ensure electric power entities know how to effectively report their purchases of asset controlling supplier power".* As MSCG argued in more detail in our initial comments submitted on October [5, 2013], the mere use of the word "specified" or "unspecified" by the ACS entity should not determine the claim that can be made under the Cap & Trade Program. Indeed, this "seller's choice" is fundamentally at odds with the environmental integrity of the Cap & Trade Program. The label has nothing to do with the intrinsic nature of the underlying power. Moreover, since both of the current ACS entities import power directly into California, allowing these sellers to withhold the specified designation unless a purchaser pays a premium **for the exact same power imported to California,** drastically alters the competitive landscape for wholesale markets. Thus, if one extends the “seller’s choice” principle to its logical conclusion, the result will be a dramatically increased potential for unnecessary power cost increases for California consumers. Such an arbitrary allocation of economic value/cost in no way benefits either the Cap & Trade Program or California consumers. [F 11.02 – MSCG]

Response: ARB staff appreciates the commenter’s support regarding the seller choice issue. See also response to comment B-2a.

L-27. 95111 Regulation Provides non-ACS Entities More Control Over Sales than BPA Has

Comment: Under the current regulations, non-ACS entities can knowingly sell resources as unspecified simply by withholding some of the transaction data, like “meter data,” that CARB requires for verifying that a source was specified. For example, an entity with a carbon-free wind resource could elect to sell their wind resource as unspecified if a buyer is not willing to pay a premium for specified status and the accompanying benefit of a lower exposure to California carbon allowance expenses. BPA has no such ability to recoup the intrinsic low-carbon value of its power when transacting bilaterally, due to CARB’s interpretation that everything BPA sells bilaterally (except pathouts) must be considered specified. This is an obvious inequity and another problem with CARB’s treatment of BPA power sales. [F 16.04 – BPA]

Response: ARB staff disagrees with this comment. ARB staff believes that by removing the seller control concept (see explanation in response to comment B-2a), there is not an inequity between an asset-controlling supplier and a specified source. ARB staff notes the commenter’s example of wind power source selling power without the attributes is unspecified is not consistent with the reporting requirements. If there is a power contract that specifies the source of power as a wind source, regardless or carbon attributes, the power would be reported as a specified source. The same logic holds true for power coming from a coal-fired power plant. However, in both cases, the wind or coal power source could sell their power on the Intercontinental Exchange and, in this case, it would need to be reported as unspecified.

L-28. 95111 SCPPA Supports the Withdrawal of the ACS Seller Control Interpretation..

Comment: The notice issued by the ARB with the proposed changes to the Regulation on October 28, 2013, states on page 3 that: Additionally, and in response to stakeholder comments, staff intends to issue revised statements in the Final Statement of Reasons to effectively withdraw the seller control interpretation for asset controlling suppliers associated with section 95111(a)(5)(B). This change is needed to ensure electric power entities know how to effectively report their purchases of asset controlling supplier power.

In the Initial Statement of Reasons ("ISOR") issued with the September Amendments on September 4, 2013, the "seller control interpretation" is explained as follows:

This change [to section 95111(a)(5)(B)] is necessary to establish that asset-controlling supplier power may be reported as either specified or unspecified power depending upon the transaction, for the reason that asset-controlling supplier power can be sold in the market as either specified or unspecified power. … It is ARB's expectation that the ACS seller controls whether the specified ACS attributes are conveyed with the transaction. For example, a renewable energy seller determines whether the renewable energy credits (RECs) convey in a transaction for specified power. Similarly, the ACS would determine whether the specified ACS attributes convey in a transaction for specified ACS power. Thus, in order to claim specified ACS power, EPEs must provide some evidence that the ACS attributes were in fact conveyed at each point along the market path shown on the eTag.

For the reasons set out convincingly in Morgan Stanley's comment to ARB on the September Amendments, the seller control interpretation is problematic. Morgan Stanley states: [emphasis added]

Yet part of the proposed amendments includes the proposed "clarification" that an ACS controls whether or not a sale is specified. This additional criterion provides absolutely no improvement to the environmental integrity of the cap- and trade program, and contradicts other parts of the regulations. Conversely, it can be construed as unwarranted interference in negotiating and contracting activities outside the state of California. Furthermore, it swings the determination of whether or not power can be reported as "specified" based solely on whether or not the seller deigns to use the word "specified", rather than on any intrinsic aspect of the underlying electricity being contracted for or the type of transaction used. Last, but not least, granting this type of arbitrary overlordship over how a transaction is reported to ARB to the seller, rather than to the buyer/importer, has the potential to raise the cost of power to California consumers.

These objections are well-founded. SCPPA looks forward to statements in the Final Statement of Reasons that clearly withdraw the seller control interpretation for power from asset-controlling suppliers. Rather than giving an ACS the ability to charge California purchasers more money for the same product, the determination as to whether a particular transaction is for ACS power should rest on the objective criteria already in place in the Regulation. Guidance materials can provide any necessary clarification on the treatment of power purchased from asset-controlling suppliers on exchanges or from points geographically remote from an ACS system.
[F 12.05 – SCPPA]

<u>Response</u>: ARB staff appreciates the commenter's support of the removal of the seller choice concept. See also response to comment B-2a.

L-29. 95111 Clarify Definitions and Provide Guidance to Resolve Seller Control Issue

Comment: For the reasons expressed in our October 22, 2013 comments on the Proposed MRR Amendments, Powerex supports ARB's decision to adopt the proposed amendment to MRR § 95111(a)(5)(B). This language is critical to maintain the consistency between power sold by ACSs and non-ACS entities while confirming the written power contract requirement for specified power. However, Powerex is concerned by the following statement in ARB's "Notice of Public Availability of Modified Text and Availability of Additional Documents"1:

> Additionally, and in response to stakeholder comments, staff intends to issue revised statements in the Final Statement of Reasons to effectively withdraw the seller control interpretation for asset controlling suppliers associated with section 95111(a)(5)(B). This change is needed to ensure electric power entities know how to effectively report their purchases of asset controlling supplier power.

With respect to "seller control," Powerex understands that ARB is not concerned with a seller having control over what channel it may choose to access the market, whether via bilateral sales or via an exchange/broker arrangement. ACSs (in today's terms, both Bonneville Power Administration and Powerex) clearly have control over whether or not they sell power bilaterally or through an electronic exchange. We agree that this is not a concern. Powerex believes it is clear that deliveries of power, sold by an ACS through an electronic exchange or broker are not contracts for specified power, but are rather for unspecified power. Similarly, deliveries made under unspecified power contracts will be assessed the unspecified rate – even if they are coincidentally delivered from the system of an ACS. Powerex understands that another form of seller control – whether or not an ACS has the ability to bilaterally sell unspecified power – is ARB's main concern. There are three related questions for which the answers are different and the question is complicated by existing ambiguous definitions:.

1. Does an importer have the right to claim power bilaterally purchased from an ACS as specified power if that power is not contingent upon delivery from the system of the ACS?

2. Does an ACS have the right to bilaterally sell specified power (i.e., power contingent upon delivery from a specified source, including its ACS system) but choose not to confer on the buyer the right to make a specified source claim?

3. If an ACS can only sell from its generating system, should an importer be able to claim power purchased bilaterally from that ACS as specified power if the contract is not explicitly for specified power?"

The MRR's current definitions of "specified source" and "asset-controlling supplier" confuse the issue with respect to all three of these questions by including within the definition of a specified source an ACS rather than the system of an ACS. This must be clarified and is addressed in Section 1.a below.

In regards to Question #1, if ARB does not clarify that a specified source is the system of an ACS, but leaves the definition as is, some parties will interpret this such that they are able to bilaterally contract with an ACS for the delivery of power from sources unrelated to the system of the ACS and be able to claim the corresponding import as from a specified source (the ACS) simply by being able to dial the phone number of ACS's trading desk. This clearly would have unintended and far reaching consequences.

In regards to Question #2, any bilateral transactions in which the contractual terms identify the source of generation and clearly obligate the seller to deliver from that source (whether it is the system of an ACS or a single electricity generating facility) should be eligible to be claimed as being from a specified source.

In regards to Question #3, it is insufficient for an importer to rely on the belief that an ACS can only sell from its generating system as the basis for a specified power claim. The only way to be sure is to explicitly contract for sources in the ACS's system. This is not the same as a seller control issue where the seller deems two different treatments for the same product; it is a matter of product clarity, and a contract that is contingent upon delivery from the specified source is the key issue. The following example may be helpful.

Consider a contract for power that includes deliveries over multiple periods where the seller owns a wind facility and has access to no other sources of generation; however, the contract is not contingent upon deliveries from that facility. On the surface, despite the fact that the contract was not explicitly for specified power, it would appear reasonable to claim any associated imports as specified power as it could not have come from any other source. The problem is that things change. Consider the possibility that shortly after the contract is executed the seller purchases the output of a thermal generating unit. Because the contract is not contingent upon deliveries from the wind facility, the seller could fulfill the contract with deliveries from the thermal unit. Clearly, this does not meet the conditions for specified power. Even the energy delivered prior to the purchase of the thermal generation should not be claimed as specified power since the contingent delivery requirement was not met "at the time the transaction [was] executed." Instead, had the contract met the contingent delivery requirement, the seller's subsequent power purchase would not have impacted the delivery requirement and a specified power claim would have been justified.

The same would apply to an ACS. Just because an ACS can only sell power from its ACS system today does not mean that that will continue tomorrow. Many aspects of this could change. The ACS may alter its activities, it may change the footprint of its ACS system, or certain statutes may change that would allow an ACS to deliver power from other sources. Accordingly, it is imperative that specified power claims explicitly meet the requirements of a "written power contract."

The common denominator is the "written power contract" requirements for "specified" power claims. Provided "specified" power claims are governed by the "written power contract" requirements – and the definitions are clarified as recommended below – the seller control issue can be resolved via specific guidance directing whether certain contracts meet the "written power contract" requirements in that special case. Accordingly, we recommend ARB include language along the lines of the following in the FSOR to address this:

> Response: We agree that regardless of any seller control restrictions placed on asset-controlling suppliers, the written power contract requirements govern for all specified power claims.

in order to ensure specified power claims are applied consistently ARB must clarify two critical definitions in the MRR so as to not create unintentional consequences. Our comments below address this issue. [F 19.01 – PX]

Response: Regarding the definition changes, the commenter is referred to response to comments K-4 and K-5. ARB staff notes that the commenter's interpretation of the seller control concept is consistent with response to comment B-2a. ARB staff has the following responses for Powerex's specific questions:

Question 1: ARB staff has addressed the issue of path outs in the response to comments B-5a-c and L-16. Based on these responses, an importer does not have the right to claim power bilaterally purchased from an asset-controlling supplier as specified that is not contingent upon delivery from the asset-controlling supplier's system.

Question 2: See response to comment B-2a.

Question 3: For the case of Powerex, if a power contract is written for Powerex ACS power, then the importer can claim the ACS emission rate. However, if the power contract is for power outside of the facilities/units that constitute the ACS footprint, then the ACS emission factor would not be allowed to be claimed. In this case, the power contract for ACS power is the driving factor that allows for an importer to claim the ACS emission factor. In order to claim a specified source, an electric power entity must have a power contract and associated NERC e-tags.

L-30. 95111. Supports Removal of System Power Provisions

Comment: The proposed changes to the Regulation include the deletion of all provisions and definitions relating to "system power." SCPPA supports the removal of the system power provisions. These provisions were unclear and problematic. For example, it was unclear how the systems would be determined and how the system-specific emissions rate would be calculated, and it was also unclear in what circumstances power from such a system would be subject to the system-specific emissions rate and in what circumstances (if any) the default emissions rate would apply.

Furthermore, there would be a high likelihood of unintended consequences to the power market throughout the Western Electricity Coordinating Council ("WECC") area if the system power provisions were implemented, as entities would seek to revise, swap, or terminate existing contracts to avoid the application of the high system-specific emissions rates. As noted by PacifiCorp in its comments on the amendments to the Regulation released for 45-day public comment on September 4, 2013 ("September Amendments"), "the application of system emission factors has the potential to cause a significant shift in the entire market."

Finally, it would have been inappropriate to implement the system power provisions without also revising the default emissions factor for unspecified electricity to account for the reduced emissions intensity of the rest of the WECC-wide electricity pool once the higher-emitting systems were separated out. [F 12.01 – SCPPA]

Response: ARB staff appreciates the support of the commenter regarding the removal of the system power language. Additionally, see response to comment B-2a.

L-31. 95111. Guidance for Verifiers Should be Published.

Comment: SCPPA requests the ARB to publish guidance and training materials for use by verifiers when verifying reports by electric power entities. Given the complexity of the reporting requirements for this sector and the significant recent changes, it would be useful for such guidance to be publicly available.
[F 12.06 – SCPPA]

Response: See response to comment P-6 [F 04.06].

L-32. 95111. Power Sold as Specified and Unspecified

Comment: BPA wishes to confirm and memorialize CARB staff's direction in the November 5, 2013 phone call regarding how BPA power can be sold as specified and unspecified. Based on the November 5, 2013 phone call with CARB staff, BPA's present understanding of CARB's guidance is as follows. CARB will construe BPA power as specified when a buyer calls BPA directly and arranges to buy power bilaterally from BPA. CARB will construe BPA power as unspecified when BPA sells power anonymously through a broker or through an electronic exchange such as ICE.
[F 16.01 – BPA]

Response: ARB staff agrees with the commenter. In cases of selling BPA power bilaterally through contract, the BPA power is specified. When the BPA is sold anonymously through a broker or ICE, the BPA power is unspecified.

L-33. 95111. Identification of BPA Transactions as Specified or Unspecified

Comment: The distinction CARB has drawn is overly simplistic because there may be situations in which a buyer acquires BPA power through a broker or an exchange and knows up front that it is contracting with BPA. Ultimately CARB will need a means for determining whether the transaction was anonymous or whether the buyer knew it was buying from BPA. It seems CARB's rationale is premised entirely on whether a buyer knows, at the time of entering into the transaction, that it is transacting with BPA. CARB is basing this on the fact that federal law permits BPA to sell power from only one system, which to date has been the same system mix that BPA has registered as its ACS system with CARB. Thus, CARB's logic is that when a buyer transacts directly with BPA that buyer knows it is receiving power from BPA's ACS system, so CARB will construe this as a transaction for BPA ACS specified power.

The practical result of this rationale is that CARB will now have to police whether a buyer knew, at the time of the transaction, that it was dealing with BPA. CARB cannot accomplish this merely by looking at whether a transaction was done bilaterally versus through a broker or an exchange.

That is, CARB's logic regarding whether or not BPA transacted with pure anonymity will be difficult to validate. For example, an e-tag from a buyer who is matched up with BPA through a broker transaction will not look any different than an e-tag for a buyer that contacted BPA directly to buy power bilaterally. CARB will need to be prepared to police transactions (through some other means beyond simply reviewing e-tags and power contracts) to determine whether a buyer knowingly purchased power from BPA directly and therefore is entitled to claim the power as specified, or whether the buyer did not know who the seller was and therefore would have to claim it as unspecified.

Power contracts do not identify anonymity. For example, BPA can chose whether or not it wants a broker to identify BPA as the seller when communicating our sales price to the market. The power contract would show that a transaction occurred with the help of a broker, but the power contract does not identify whether BPA used the broker to sell the power anonymously. If BPA did not request anonymity in the brokered transaction, BPA's understanding (from the November 5th phone call with CARB) is that the transaction would qualify as specified because the buyer would know, at the time of entry into the contract, that it was purchasing from BPA.

Here again though, CARB will need some means for determining whether or not transactions occurred with complete anonymity in order to ascertain whether an import of BPA power into California is eligible to be claimed as specified or unspecified. Today's contracts and confirms do not address anonymity, the MRR language does not address it, and proof of anonymity will be difficult to enforce within the current MRR rules.

With regard to electronic exchanges, currently the predominant electronic exchange (ICE) used to transact Day Ahead power in the Pacific Northwest provides anonymity prior to executing a transaction. However, markets evolve and anonymity could be removed from ICE (or other exchanges that might be launched in the future). It is simplistic to assume absolute anonymity will always govern how electronic exchange and brokered transactions will occur in the future.

The bottom line is that, if CARB intends to base the distinction of whether BPA power is specified or unspecified on whether a buyer knows (at the time of entering into the transaction) that it is transacting with BPA, then CARB will need some means for verifying anonymity or the lack thereof at the time a transaction occurs. CARB regulations are currently devoid of guidance on how this will be verified. [F 16.02 – BPA]

Response: ARB staff appreciates the commenter's further explanation on how BPA tags and contracts for power on the market. The structure of reporting is based upon an e-tag and a power contract. Based on this comment, it seems the bilateral contract between BPA and a purchaser is straightforward. Additionally, if the power is sold non-anonymously through a broker (i.e., the buyer specifies it wants to purchase BPA ASC power), the power could also be considered specified. The nuances that the commenter discusses regarding an "anonymous specified contract" and the potential for markets like ICE to evolve are interesting concepts, but ARB staff disagrees that this is difficult to monitor. Sections 95105(b), 95131(f), and 95131(g) allow ARB to request any and all data used to generate the emissions data report. Moreover, verification will require the reporting entity to demonstrate to the verifier whether the power was specified or unspecified. Additionally, if, during the course of an ARB audit, it was found that an "anonymous specified contract" was truly just a transaction on ICE, the reporting entity that misreported this information would be subject to the enforcement provisions of section 95107. As needed, ARB staff is committed to work with the commenter to better understand the nuances of this contracting type and the magnitude at which it may occur.

L-34. 95111(g)(1)(N). Ramifications of Retaining Phrase of "at the time the power was directly delivered" is Not Clear

Comment: LADWP recommends that the phrase "at the time the power was directly delivered" be deleted because it is overly restrictive and does not allow sufficient latitude for verifiers to use an alternative verification approach such as Method 2 (described below).

(g) Requirements for Claims of Specified Sources of Electricity and for Eligible Renewable Energy Resources in the RPS Adjustment.

***

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

***

(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.

During verification of the 2012 reports in 2013, it was unclear how this section of the rule should be interpreted and applied. Since it is under *"Registration Information for Specified Sources and*

Eligible Renewable Energy Resources in the RPS Adjustment, it would appear the reporter only needs to retain the data and make it available to the verifier.

However, based on recent discussions with ARB staff, LADWP is concerned about what reporters and verifiers may be expected to do with the hourly meter data. ARB's current thinking is the meter data should be used to subdivide hourly data into specified and unspecified. This would be done by comparing hour-by-hour generating facility meter data with delivered electricity (NERC e-tag) data, and claim the lesser of the two for each hour as specified and the difference as unspecified.

This interpretation is concerning for the following reasons:

- It is too narrowly focused on the accuracy of hourly data rather than the accuracy of annual data for an annual report.
- Performing an hour-by-hour analysis for every specified import and renewable energy resource in the RPS Adjustment would significantly increase the reporting and verification burden, but the end result would not be significantly different than reporting whole e-tag data.
- It appears to conflict with the reporting requirements in 95111(a) that require Electric Power Entities to report delivered electricity, which is e-tag data not meter data.
- In some cases, taking this approach would actually be detrimental and make the report less accurate by understating the amount of electricity imported from the specified source on an annual basis.

The original September 4, 2013 amendment to delete "at the time the power was directly delivered" from 95111(g)(1)(N) was beneficial because it would have allowed flexibility for the verifiers to exercise their professional judgment and choose a verification approach that is appropriate to each particular case or situation. Retaining this phrase limits what approach the verifiers can use to verify specified imports and the RPS Adjustment in the annual report.

Requirements in the reporting regulation should not be overly restrictive.

LADWP evaluated two different verification approaches using generating facility meter data to verify the accuracy of specified imports based on e-tag data.

Method 1 (Hour-by-Hour Comparison): Align and compare hourly generating facility meter with hourly e-tag data, select the lesser of the meter or e-tag data for each hour and sum the results.

Method 2 (Monthly/Annual Comparison): Compare the entity's share of the facility net generation meter data with the specified import (based on e-tag data) on a monthly and/or annual basis, and calculate the deviation. If the deviation between the entity's share of the facility net generation and the delivered electricity is less than five percent on an annual basis, this should satisfy the five percent accuracy requirement in the MRR.

Findings and Results

The Method 1 approach was a complex and labor intensive process. In order to compare hourly meter and e-tag data, the raw data needed to be summed, transposed, and shifted to adjust for time zone differences. There were multiple opportunities for making errors while preparing and aligning the data for the hour-by-hour comparison. After all that work, the difference was less than significant (1.63%).

The Method 2 approach was much simpler. This approach used monthly meter data reported by the generating facility and monthly subtotals of the e-tag data. Very little data preparation was needed to set up the meter and e-tag data monthly/annual comparison and calculate the deviation. Since this method did not require summing of hourly MWh from multiple e-tags or shifting meter data to adjust for time zone differences, there was much less chance of making errors. The annual deviation between the meter and e-tag data was less than significant (1.59%)

For the sample month to which the Method 1 hour-by-hour comparison was applied, the generating facility meter data was 1.84% higher than the sum of the MWh on the e-tags, which was 1.63% higher than the sum of the lesser of the meter or the e-tag data for each hour. Generating facility meter data may not reflect station service, transformer or line losses. The 1.84% difference between the generating facility meter and the e-tag data represents the line losses from the generating facility to the first point of receipt.

The Method 1 approach would be difficult for the verifier to determine with reasonable assurance that the sum of the "lesser of the meter or e-tag for each hour" is accurate on an annual basis. The verifier can review the process and do spot checks of the hourly data, but given the potential for making errors while preparing the data for comparison, the only way to know for sure that the result is accurate would be to review and/or replicate the hour-by-hour analysis. The Method 2 approach would be fairly easy to verify by reviewing monthly generation reports from the generating facility and re-running the query of the e-tag database.

Conclusions

Comparing hourly generating facility meter data vs delivered energy (e-tag data) and selecting the lesser of the two for each hour is a very complex and labor intensive process that produces a less than significant difference that is well below the five percent accuracy threshold. Therefore, the extra labor required to perform this hour-by-hour analysis does not add value.

The Method 1 approach to verifying specified imports by comparing hourly meter and e-tag data has limited usefulness – it can be applied only in cases where the entity receives a fixed percentage of the facility net output for every hour throughout the year. This approach does not work in cases where the electricity delivered to the entity does not reflect a fixed percentage of the generating facility net output for every hour. Therefore, this approach cannot be applied across the board for verifying all specified imports and the RPS Adjustment.

The Method 2 approach to verifying specified imports by comparing the entity's share of the annual generating facility net output (meter data) with electricity delivered to the entity (e-tag data) is a much simpler approach that is just as effective and requires much less labor than the hour-by-hour approach. This approach can be tailored to apply to a wide variety of electricity import arrangements, including cases where electricity delivered to the entity does not reflect a fixed percentage of the generating facility net output for every hour. This approach enables the verifier to review the overall disposition of the electricity from the specified source belonging to the reporting entity.

LADWP believes Method 2 is a reasonable approach for verifying the annual specified imports are not over or under stated in the annual report. Therefore, LADWP recommends the phrase "at the time the power was directly delivered" be deleted because it is overly restrictive and does not allow sufficient latitude for the verifiers to use an alternative verification approach such as Method 2.

[F 18.01 – LADWP]

Response: ARB staff appreciates the commenter's support of the 15-day modifications made to section 95103(h)(8) and the removal of system power. See response to comment B-12j regarding the administrative burden and the hourly data response. ARB staff notes that the annual report is based upon e-tags, which are at the hourly level. In order to verify the e-tags are correct, a comparison at the hourly level is needed. ARB staff believes the hourly data method would not underestimate the amount of power coming to California on an annual basis, but be an accurate verification check because it allows for a direct comparison to the e-tags. ARB staff would like to reiterate its commitment to working with entities to ensure the requirements are clear and that there are adequate means for all entities to comply with this provision.

L-35. 95111. If ARB Withdraws the Treaty Power Provisions, it Must Clarify how Such Power is to be Treated Under the MRR

Comment: In its comments on ARB's July 17, 2013 discussion draft of proposed MRR amendments, Powerex proposed, among other things, that ARB amend the MRR so as to accommodate power imported under an international treaty.3 As Powerex noted, power received pursuant to international treaties, including, but not limited to, the Columbia River Treaty, does not fit within the MRR's existing framework.4 While CE power meets the "spirit" of specified power and should be treated as specified power given its origins, under the MRR it does not cleanly meet the current definition of specified power because it does not appear to meet the definition of a written power contract. To address this problem, Powerex proposed definitions for "international treaty," and "treaty power," as well as other minor adjustments to the MRR.

Recognizing the need to address this issue, ARB included amendments in its September 4, 2013 45-day package of proposed MRR amendments that were similar to Powerex's proposal. The proposed amendments included a new definition for "treaty power" (MRR Section 95102(a)(476)); treaty power also was incorporated into both the specified source calculation (MRR Section 95111(b)(3)) and the ACS application process (MRR Section 94111(f)(5)(F)), and into the definition of a Power Contract (MRR Section 95102(a)(351)). The changes adequately addressed Powerex's concerns regarding the treatment of CE energy for the purposes of specified source calculations and ACS applications.

While Powerex had proposed a broad definition of "treaty power" that would encompass any international treaty, ARB chose a different, limited definition of "treaty power" that covered only CE energy. See MRR Section 95102(a)(476) ("Treaty Power" means electricity returned to Canada from the United States under the Columbia River Treaty."). It appears that such a narrow definition caused some stakeholders to become concerned that ARB's treatment of treaty power could be seen as interference by California with ongoing Columbia River Treaty negotiations. Apparently to avoid such an interpretation, ARB now proposes to strike all of its proposed "treaty power" amendments that were included in the 45-day proposed amendments.

b. Deleting the Treaty Power Provisions Does Not Resolve the Problems in reporting Treaty Power. Powerex believes that stakeholder comments did not necessitate ARB's complete elimination of treaty power from the MRR, and ARB still needs to resolve how treaty power is to be treated under the MRR. Otherwise, Powerex will have no way of knowing how it should treat CE energy in its annual ACS applications. Under the MRR's current definitions, it appears as though it can be classified as specified power, nor is it appropriate to classify it as unspecified power. There are no other "buckets" to which to assign this power though. Therefore, to address the concerns raised by certain stakeholders while still accommodating treaty power, we recommend that ARB adopt the proposals set forth in Powerex's August Comments.

If ARB concludes that regulations dealing with treaty power cannot be incorporated into this round of MRR amendments, at a minimum ARB should provide clear guidance in its FSOR upon which Powerex can rely. That guidance should state that that CE energy will be treated as specified source power until such time as ARB promulgates regulations specifically dealing with treaty power, regardless of the fact that treaty power does not fit the exact definition of specified source power because it lacks a written contract. Otherwise, low-carbon energy managed under international treaties such as the Columbia River Treaty will have to be managed as unspecified power to avoid a claim that Powerex is improperly claiming energy as a specified power in its ACS application. Unspecified source designation is inappropriate for hydroelectric CE energy, and is inconsistent with the goals of the program.

As discussed above, ARB should instead adopt the broad language Powerex proposed in its August Comments. In the alternative, Powerex strongly encourages ARB to include language in the FSOR along the lines of the following:

> **Response:** We agree that Canadian Entitlement power should be treated as specified power for Powerex's annual ACS applications.

[F 19.03 – PX]

Response: See response to comment A-21. ARB staff declines to adopt the requested FSOR response for the reasons stated in response to comment A-21.

§95112 – Electricity Generation and Cogeneration Units

L-36. 95112. Guidance for Section 95112 Electricity Generation and Cogeneration Units

Comment: ARB proposes new amendments that state if a facility includes more than one electricity generating unit or cogeneration system and each unit/system or each group of units generate electricity for different particular end-users or retail providers or electricity marketers, the operator must separately report the disposition of generated electricity by unit/system or by group of units.

Guidance Language: ARB should clarify that if a facility generates its own thermal energy within the facility boundaries and the thermal energy is used by the same company within its own on-site industrial processes then the operator can report the total amount of thermal energy as a total. [F 10.19 – WSPA]

Response: See response to comment L-5 [F 10.18]

M. Subarticle 2. Petroleum Refineries, Hydrogen Production, General Combustion

§95113 – Petroleum Refineries

M-1. Comment: Air Products recommends the inclusion of the CWB factor for gaseous hydrogen production in Table 1 of §95113(l)(3). Further, the reporting obligation for all hydrogen production (refinery-owned and merchant-owned facilities) should be in units consistent with the CWB factor for hydrogen.[§95113(l)(3)]

ARB is still considering alternative approaches for the benchmark derivation and allocation of allowances for hydrogen production under the cap & trade program. Both Air Products and the Western States Petroleum Association (WSPA)[1] have included recommendations in their respective formal comments that the ARB base the hydrogen allocation on the CWB approach. As such, the MRR needs to be modified to allow for the proper data collection to support this possible cap & trade program approach.

Reporting hydrogen production according to the CWB methodology requires the inclusion of the relevant hydrogen production CWB factors in Table 1 of §95113(l)(3). The CWB factor for hydrogen should be those included in the report[2] prepared by Solomon Associates on behalf of WSPA and submitted to CARB in May 3013. Appendix C "Comparison of CWB and CWT Factors for Process Units (CA-CWB vs. Solomon EU CWT)".

Hydrogen factors include:

- Steam-Methane Reforming – 5.7 CWB/k SCF/cd
- Steam-Naptha Reforming – 6.7 CWB/k SCF/cd
- Partial Oxidation – 7.1 CWB/k SCF/cd

For consistency, ARB should also require all "on-purpose" hydrogen production to be reported in "k scf", units consistent with the hydrogen CWB factor [§95113(l)(3)(A)] [F 13.01 – APC]

Response: See response to comment M-5 [F 10.01]

M-2. 95113. Petroleum Refineries – CWB

Comment: WSPA supports ARB's proposed action to report changes to GHG emissions. WSPA supports ARB's proposal to use CWB instead of CWT and recommends ARB make all necessary revisions and corrections as necessary to support CWB. [F 10.11 – WSPA]

Response: ARB staff appreciates the commenter's support. See also response to comment D-3.

M-3. 95113. Petroleum Refineries – Meter Calibration for Product Data

Comment: Ensuring Quality and Accurate Data. WSPA appreciates and understands the need for meeting the data quality and accuracy requirements per the Cap and Trade and MRR programs. However, mandating meter calibrations will not in and of itself produce the accuracy required by the rules. There are instances where operators need flexibility to use alternative techniques and engineering calculations to prepare accurate reports. In these instances, engineering calculations and/or alternate data capture methods will produce data of comparable accuracy to that provided by direct metering. In fact, in some of these same cases, metering will not provide the level of accuracy desired by operators and ARB. In such instances, use of an alternate method is essential if the accuracy required by 95113 is to be attained.

Recommendation: Delete 95113(l)(3)(E) to recognize use of k(11) methods. Insert an appropriate corresponding change to revise 95103 (k)(11) so that it would still be applicable to CWB by reference to 95113(l)(3). Note: should ARB not accept the recommendation for inclusion of K(11) for CWB, then any requirement to submit 7 postponement requests by April 10, 2014 should be deferred until September 1, 2014 (which corresponds to the verification date). To summarize, delete 95113 (l)(3)(E) to allow the use of 95103(k)(11) and include in Section 95103 (k)(11) a reference 95113(l)(3). [F 10.12 – WSPA]

Response: See response to K-14 [F 10.02] regarding the measurement accuracy language. ARB staff declines to extend the postponement submittal date from April 10, 2014 to September 1, 2014. The evaluation of postponement requests are resource intensive and normally need to be completed by the end of a calendar year. ARB staff is willing to work with the commenter by offering suggestions for streamlining postponement requests for a timely submittal of materials.

M-4. 95113. Complexity Weighted Barrel

Comment: Complexity Weighted Barrel (CWB). WSPA supports the adoption of the Complexity Weighted Barrel (CWB) method, with further edits as recommended in these comments. Please see our comments on the omission of Hydrogen Plant factors (above) and on Section 95113(l)(3)(b) that identifies definitions and critical omissions in the calculation of CWB with regard to non-crude sensible heat, offsites, and non-energy utilities. [F 10.03 – WSPA]

Response: ARB staff appreciates the commenter's support for the inclusion of the complexity weighted barrel factors. See response to comment M-5 [F 10.01] regarding hydrogen plant factors and response to comments K-10, M-6, M-8 [F 10.13a-c] regarding non-crude sensible heat, offsites, and non-energy utilities.

M-5. 95113. Omission of Hydrogen Plant CWB Factor (Table 1)

Comment: WSPA is very concerned that the CWB factors for hydrogen generation (using steam methane reforming, steam naphtha reforming, or partial oxidation) were omitted from Table 1. This omission makes it virtually impossible to correctly account for emissions from hydrogen facilities within the Cap and Trade program. Even if ARB plans to address the treatment of hydrogen plants as part of the Cap and Trade Rule scheduled for finalization in early 2014, this omission is very problematic, given that the MRR requirements become effective January 1, 2014.

To assure integrity of the MRR program, to facilitate reporting, and to ensure the equitable treatment of hydrogen plants under the Cap and Trade Program, ARB must include the CWB factors for all hydrogen process types. Recommendation: Include the CWB factors for the 3 hydrogen generation process types provided by WSPA/Solomon in August, 2013 and as shown below:

Steam Methane Reforming	5.70
Steam Naphtha Reforming	6.70
Partial Oxidation Units	7.10

[F 10.01 – WSPA]

Response: See response to comment D-4. Additionally, ARB staff declines to put in CWB factors for steam methane reforming, steam naphtha reporting, and partial oxidation units because they all relate to hydrogen generation processes.

M-6. 95113. CWB Calculation

Comment: WSPA recommends that MRR Section 95113(l)(3)(B) be revised for proper calculation of CWB contribution from $CWB_{\text{Offsites and Non-Energy Utilities}}$ and $CWB_{\text{Non-Crude Sensible Heat}}$:

S 95113(l)(3)(b*) Total facility CWB*. The total facility CWB production must be calculated according to the following formula.

$CWB = \Sigma\ (CWB_{Factor} * Throughput) + (CWB_{Off\text{-}sites\ and\ Non\text{-}Energy\ Utilities}) + (CWB_{Non\text{-}Crude\ Sensible\ Heat})$

Where:

"CWB"' = The total amount of complexity weighted barrels from a petroleum refinery.

'CWB_{Factor}" = The CWB factor for each process unit found in Table 1 of this section.

"Throughput" = The reported value for each CWB function identified in Table 1 of this section reported pursuant to section 95113(l)(3)(A).

"$CWB_{Offsites\ and\ Non\text{-}Energy\ Utilities}$" = 0.327 * Total Refinery Input + [0.0085 * Σ(CWB_{Factor} * Process CWB)]

"$CWB_{Non\text{-}Crude\ Sensible\ Heat}$" = 0.44 * Non-Crude Input

[F 10.13b – WSPA]

Response: ARB staff declines to make this change because it would lead to double counting. As written by the commenter, the change counts CWB factor "non-crude input" twice: once in the sum of CWB_{factor} * throughput and then again in the suggested variable, $CWB_{non\text{-}crude\ sensible\ heat}$. The current structure of the requirement ensures the CWB throughput "non-crude input" is accounted for only once.

M-7. 95113. Errors In Table 1 of Section 95113

Comment: We note some errors in Table 1, specifically with respect to consistent use of units of throughput. We note them below. If conversion is needed, ARB should note that where appropriate.

- As noted above, all CWB factors for Hydrogen production (Steam Methane Reforming, Steam Naphtha Reforming, and POX for Hydrogen) are missing.
- Residual FCC is missing.

- The following should be on product vs. feed basis (these are incorrect or partially incorrect in the ARB Table):
  - C4 Isom
  - C5/C6 Isom
  - Hydrodalkylation
  - Toluene Disproportionation
  - Xylene Isomerization
  - Para Xylene Production
  - Ethyl benzene Production

[F 10.08 – WSPA]

Response: See response to comment M-5 [F 10.01] regarding the complexity weighted barrel hydrogen generation functions. ARB staff notes that there is a complexity weighted barrel term for “mild residual FCC” which has the same factor (5.50) as “residual FCC.” ARB declines to make the change because this factor is already covered in Table 1 in section 95113 of the MRR. ARB staff declines to make the changes regarding labeling of the throughput basis because the throughput basis does not affect the units of the measurement for the throughput.

M-8. 95113. Modifications to Table 1 of Section 95113

Comment: WSPA recommends the below changes to MRR Table 1 including the slight reordering of these factors to be intuitive for calculation of $CWB_{\text{Offsites and non-Energy Utilities}}$ and $CWB_{\text{Non-Crude Sensible Heat}}$”

Total Refinery Input	Feed	Thousands of barrels/yr	0.327		For calculation of $CWB_{\text{Offsites and Non-Energy Utilities}}$
Process CWB	CWB	CWB/year	0.0085		CWB excluding CWB $_{\text{Offsites and Non-Energy Utilities}}$ and excluding CWB $_{\text{Non-crude Sensible Heat}}$ - ; this term is also used in

					calculation of CWB Offsites and Non-Energy Utilities
Non-Crude Input	Feed	Thousands of barrels/yr	0.44		For calculation of $CWB_{Non\text{-}Crude\ Sensible\ Heat}$"

[F 10.13c – WSPA]

Response: ARB staff believes the current CWB equation will result in the same total CWB values as the changes requested by the commenter and therefore declines to make the commenter's requested changes. Further clarification may be provided in guidance.

§95114 – Hydrogen Production

M-9. Comment: Air Products does not support adding a requirement for hydrogen producers to provide carbon and hydrogen content for all feedstocks. Such a requirement adds compliance costs with no material gain toward informing the overall state GHG emission inventory. [§95114(e)(1)]

This issue was considered under the 45-day amendments and Air Products acknowledges that staff did reduce the sampling burden for other gaseous fuels from an initial proposal of daily, to monthly. Nevertheless, this requirement increases the cost of compliance for hydrogen production facilities in the following ways:

A. Facilities that made the irrevocable decision (under 40CFR98) to employ CO_2 CEMS, consistent with 40CFR98.163(a), made such investments as a means to avoid the more significant costs associated with sampling, analyzing, and measuring the flow of multiple fuel and feedstock streams used to produce hydrogen at that facility. Both US EPA and the CA ARB have accepted CEMS emissions determinations for compliance reporting.

   While the capital, operating, calibration and maintenance costs for proper operation of a CO_2 CEMS is also significant, the "elegance" of a CEMS approach is that it does not require the multiple sampling, analysis flow measurement, and data handling tasks (and costs). Under the October approved §95114(e)(1)(A) amendments, monthly analysis for carbon and hydrogen content is required for all gaseous feedstocks, including natural gas. Typical natural gas supplier data, even when available monthly, does not provide hydrogen content values, necessitating sampling and analysis for even a stream that has negligible hydrogen content and variability from standard specification values. This requirement to sample and analyze gaseous feedstock streams adds compliance costs - sampling, shipping, contract lab analysis, and data management requires in excess of $500 per sample – so characterization according to §95114(e)(1)(A) standards results in an additional cost of $6,000 per year for each feedstock. Costs for installing and maintaining feedstock flow measurement devices (needed to calculate the carbon and hydrogen content of the feedstocks as a "weighted average") further increase the capital, calibration and maintenance costs to satisfy the feedstock characterizations required under the approved §95114(e)(1)(A) amendments.

The currently approved amendment to the MRR requires facilities that have already committed to a CEMS approach to incur these large, redundant costs to characterize their feedstock streams. These added costs are particularly unwarranted because the information the ARB will garner from the characterization of feedstocks will not effectively inform either their statewide emission inventory or support their efforts to derive and administer allowance allocation benchmarks under the cap & trade program. Air Products engaged ARB staff in an attempt to determine how feedstock characterization data will enhance the ARB's understanding/quality of the components of AB-32, but cannot ascertain any such benefit. Suggestions that theoretical calculations from hydrogen production and feedstock data will be useful, ignore the realities of process variability, equilibrium limitations of the chemical reactions taking place, process-critical recycle streams employed, degradation of catalyst activity over time, equilibrium limitations of crude hydrogen purification and numerous other real-world process deviations from theoretical or stoichiometric calculations as to render such "academic" exercises useless.

B. For facilities that chose to comply with the MRR using the fuel and feedstock mass balance approach, §95114(e)(1) indicates only carbon content and molecular weight determinations are required, which is consistent with the data required to calculate the GHG emissions according to 40CFR98.163(b).. Air Products recommends that ARB modify the language of §95114(e)(1)(A) to clearly articulate that the requirement to characterize feedstock hydrogen content does ***not*** extend to facilities that are not monitoring CO2 emissions with a CEMS. As written, it can be inferred that §95114(e)(1) applies to both CEMS and non-CEMS monitoring methods, and §95114(e)(2) is an "in addition to" rather than an "instead of" requirement.

Air Products strongly recommends ARB reconsider the requirements for this costly and low/no benefit feedstock sampling and characterization. We again recommend eliminating any sampling and analysis requirements imposed on pipeline natural gas feedstocks, and further recommends eliminating or reducing the sampling and characterization requirements for other gaseous feedstocks, except as otherwise needed to calculate the facility's GHG emissions.

[F 13.03 – APC]

<u>Response:</u> See response to comment D-7.

M-10. Comment: Air Products does not support adding a requirement to report CO_2 and CH4 emissions from waste gases directed to hydrogen plant flare systems [§95114(g) and §95114(l)]

This issue was considered under the 45-day amendments, with the ARB's decision to leave intact the requirement to quantify and report this minor emission source. Air Products strongly recommends ARB reconsider this reporting requirement. Air Products' hydrogen production facilities across the U.S. report emissions under 40CFR98 Subpart P. EPA's Subpart P recognizes that flare GHG emissions are negligible for hydrogen plants. Under 40CFR98.30(b)(4), emissions from flares are exempt from reporting unless otherwise required by provisions of another applicable Subpart (in this case, Subpart P). Subpart P does not require reporting GHG emissions from flares.

Air Products asks ARB's to reconsider their rationale for imposing the additional administration, calculation, recordkeeping and reporting tasks (and costs) of such negligible emissions. In §95114(l) of the MRR regulation approved by the Board in October applies the flare emission calculations methodologies of §95113(d) (Petroleum Refineries), a method that is overly burdensome The §95113(d) requirements reference 40CFR98 Subpart Y methods – emission estimating methodologies and reporting requirements specifically tailored by US EPA to Petroleum Refining facilities in recognition that the facilities covered under that Subpart are likely to have flare emissions which are not de minimis… and thus appropriately should have a requirement for estimating and reporting. Applying these methods to the negligible emissions of hydrogen production units is disproportionate. This is further demonstrated by the fact that under the initial versions of California's MRR, when flare emission reporting was imposed, our hydrogen plants could routinely demonstrate that the emissions satisfied the de minimis reporting threshold. Air Products again recommends the requirements of §95114(g) and (l) be eliminated. [F 13.04 – APC]

Response: See response to comment D-9.

M-11. 95114. Reporting of Hydrogen Section 95114(e)(1) and (e)(2)

Comment: ARB is proposing revisions to Section 95114(e)(1) and (e)(2) that will require reporters to sample for carbon and hydrogen content for each feedstock for hydrogen production units. Furthermore, the sampling frequency for carbon content from refinery fuel gas differs in sections (e)(1) and (e)(2). Specifically, Section 95114(e)(1) states monthly sampling for carbon content and hydrogen content from fuels such as refinery fuel gas is required, whereas Section 95114(e)(2) states daily sampling for carbon content and molecular weight from fuels such as refinery fuel gas is required.

It is unclear why daily sampling for carbon content and molecular weight from fuels is necessary to develop representative values. Nor is it clear why ARB is requiring reporters to sample for the hydrogen content and how this data will be useful in better delineating process and combustion emissions. Most facilities already track process feed and combustion emissions separately so there should be no need for adding additional reporting obligations that are unnecessary.

Recommendation: ARB should remove the requirement in (e)(1) for "hydrogen content" data and the sampling requirements for both (e)(1) and (e)(2) should be required on a monthly basis.

[F 10.14 – WSPA]

Response: See response to comment D-8.

M-12. 95114. Guidance for Section 95114(j)

Comment: ARB's intent in this reporting section is unclear. Additional guidance is needed. For example, if hydrogen gas is sold then the "…annual masses of on-purpose hydrogen and by-product hydrogen produced must be reported (metric tons)". Currently, as written, it is difficult to determine if hydrogen gas is NOT sold, then are on-purpose and by-product hydrogen produced required to be reported?

Guidance Language: ARB should clarify the intent and reporting requirements hydrogen gas product data. [F 10.21 – WSPA]

Response: See response to comment D-8.

§95115 – Stationary Fuel Combustion Sources

M-13. Product Data

Comment:

We have reviewed the proposed staff amendments to the Mandatory Reporting regulation and request that the ARB consider revising proposed section 95115(n)(17) to properly address nut processing facilities in California. Paramount Farms recommends replacing the current language of proposed section 95115(n)(17) with the following:

(17) The operator of a pistachio processing facility must report the sum of pistachios (in short tons) hulled and dried, and/or flavored and packaged where the hulling and drying is a continuous process that can be independently operated from flavoring and packaging, which is a continuous process. The

reported totals of pistachios will consist of the following categories: Pistachio Hulling & Drying and/or Pistachio Flavoring & Packaging. The operator of an almond processing facility must report the sum of almonds (in short tons) pasteurized, blanched and/or flavored and dried where flavoring and drying is a continuous process. The reported totals of almonds will consist of the following categories: Almond Pasteurization, Almond Blanching, and/or Almond Flavoring & Drying.

Paramount Farms believes the above modified language provides the necessary clarifications on reporting requirements for these types of entities and adequately addresses the intention of the proposed regulations. We hope the ARB will strongly consider our recommendation for proposed section 95115(n)(17) of the Mandatory Reporting of GHG for fuel combustion sources. We appreciate the opportunity to provide our feedback on this proposal and are available should the ARB require additional input or information.

[F 05.01 – PFI]

Response: The proposed changes are technical clarifications which do not affect the reporting requirements or scope of those requirements. ARB staff agrees with the intent described by the commenter, and will provide guidance to document that the proposed regulatory requirements are in agreement with the interpretation provided by the commenter.

§95119 – Pulp and Paper Manufacturing

No comments were received on section 95119.

N. Subarticle 2. Suppliers of Transportation Fuels (§§95121, 95122, 95123)

This section was not open for comment in the 15-day comment period.

O. Subarticles 3 and 4. Additional Requirements for Reported Data and Verification

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

No comments were received on section 95129.

§95130 – Requirements for Verification of Emissions Data Reports

O-1. 95130(a)(2). Requirement for Verification of Emissions Data Reports

Comment: ARB has proposed revising Section 95130(a)(2) by adding to the list of verifications other program certifications or audits that include third party certification of environmental management systems to ISO 14001and third party certification of energy management systems to the ISO 50001 standard. Based on ARB's proposal, these previous certifications would also count toward a facility's consecutive 6-year limitation for using the same verifier.

WSPA believes the level of scope and thorough review taken to perform AB32 third-party verifications is significantly different and more stringent from those that were conducted in the above-mentioned audits. Because ARB would not consider any of these audits as an equal substitute to fulfilling AB32 verification requirements going forward, it is wrong for facilities to have to now count them if performed in the past. Many of these listed certifications were voluntarily performed in good faith to evaluate adherence with GHG requirements at the time. It is inappropriate at this time to change the rules based on wholly unrelated programs, and reporters should not be penalized by having these certifications count toward their 6-year verifier limitation.

Recommendation: Delete proposed language revisions in Section 95130(a)(2).

[F 10.09 – WSPA]

Response: See response to comment H-1.

§95131 – Requirements for Verification Services

O-2. 95131(b)(9). Correctable Errors – Emissions Data Report Modifications

Comment: This section relates to ARB's proposed revisions to Section 95131(b) (9) to require reporters to fix all correctable errors that affect covered emissions, non-covered emissions or covered product data. While WSPA members make every effort to ensure compliance with the accuracy requirements of the reporting regulation it is unreasonable to require all errors be corrected especially if the differences are of such small magnitude that they are insignificant and below the + 5% accuracy level specified in the regulation. Additionally, WSPA believes correctable errors that are within + 5% should not be considered a non-conformance event. WSPA recommends ARB revise the following section to allow reporters flexibility to work with the verification team in determining what correctable errors actually need to be corrected.

Recommendation: To incorporate the improvements noted above we recommend the following revisions to Section 95131(b) (9):

“The verification shall use professional judgment in the determination of correctable errors as defined in section 95102(a), including whether differences are not errors but result from truncation of rounding or averaging, or errors that are of such small magnitude they are determined to be insignificant.

[F 10.15 – WSPA]

Response: See response to comment H-2.

O-3. 95131(e). Correction of Identified Errors

Comment: ARB has proposed revising Section 95131(e) by including that if “an error is identified” the Executive Officer (EO) may set the positive or qualified verification aside and require the reporter to re-verify the MRR report by a different verification body. Additionally, ARB also added the following language:

“In instances where an error to an emissions data report is identified and determined by ARB to not affect the emissions or covered product data, the change may be made without a set-aside of the positive or qualified positive verification statement”.

Recommendation: WSPA recommends ARB revise their proposed revisions by clarifying that errors that do not affect the 95% level of accuracy for emissions and covered product data will not result in ARB setting aside a positive or qualified positive verification (see red font):

“In instances where an error to an emissions data report is identified and determined by ARB to not affect the 95% accuracy standard for emissions or covered product data, the change may be made without a set aside of the positive or qualified positive verification statement”.

[F 10.10 – WSPA]

Response: See response to comment H-6.

O-4. 95131(e). Section 95156(a)(7)-(10) Additional Data Reporting Requirements

Comment: ARB has amended the reporting requirements for onshore production facilities in a manner that is confusing 1 - As stated above, the term emulsion can be used in several different contexts and processes within the oil and gas industry. The current proposed definition of onshore production segment may cause confusion in the reporting requirements of 95156(a)(7)-(10).

Recommendation: WSPA recommends that the requirements be amended to reflect the specific definition of "emulsion" in the context stated in Section 95102(a)(149) as follows:

> (7) Barrels of crude oil produced using thermal enhanced oil recovery. This includes any [of] the crude oil fraction piped to an onshore petroleum and natural gas production facility as an emulsion from an offshore platform as defined in section 95102(a);
>
> (8) Barrels of crude oil produced using other than non-thermal enhanced oil recovery. This includes any crude oil fraction piped to an onshore petroleum and natural gas production facility as an emulsion from an offshore platform as defined in section 95102(a);
>
> (9) MMBtu of associated gas produced using thermal enhanced oil recovery. This includes any associated gas fraction piped to an onshore petroleum and natural gas production facility as an emulsion from an offshore platform as defined in section 95102(a);
>
> (10) MMBtu of associated gas produced using methods other than non-thermal enhanced oil recovery. This includes any associated gas fraction piped to an onshore petroleum and natural gas production facility as an emulsion from an offshore platform as defined in section 95102(a). [F 10.16 – WSPA]

Response: See response to comment I-6.

O-5. 95131(b)(9) Correctable Errors - Requirements for Verification Services

Comment: SoCalGas and SDG&E have concerns that verifiers are afforded too much power to dictate what actions must be taken regarding fixing all correctable errors, specifically under section 95131(b)(9). One of our verifier's insisted that staff correct every single error including one as small as resulting in a change of approximately one metric ton, which constituted a very small fraction of a percent of the total reported emissions. Staff was also directed to correct an emission factor that was not used for reporting purposes. Hours were spent on this exercise because no one wants to risk any type of negative reaction from a verifier who wields the power of a positive verification statement.

Suggested Language Modifications

We request that language be modified in 95131(b)(9) as suggested below (shown in red highlight and strikeout):

Section 95131(b)(9) Emissions Data Report Modifications. As a result of data checks by the verification team and prior to completion of a verification statement(s), giving the covered entity at least two weeks' notice prior to the verification deadline, the reporting entity ~~must~~ shall attempt to fix all correctable errors that result ~~affect~~ in a one percent or greater change in covered emissions, non-covered emissions, or covered product data in the submitted emissions data report. The covered entity shall~~, and~~ submit a revised emissions data report to ARB. Failure to do so will result in an adverse verification statement. Failure to make a reasonable effort to fix correctable errors that do not affect covered emissions, non-covered emissions, or covered product data ~~represents a non-conformance with this article but~~ does not, absent other errors, result in an adverse verification statement. The reporting entity shall maintain documentation to support any revisions made to the initial emissions data report. Documentation for all emissions data report submittals shall be retained by the reporting entity for ten years pursuant to section 95105.

The verification team shall use judicious professional judgment in the determination of correctable errors as defined in section 95102(a), including whether differences are not errors but result from truncation or rounding or averaging.

The verification team must document the source of any difference identified, including their professional judgment as to whether the difference results in a correctable error.

[F 17.03c – SU]

Response: See response to comment H-4

O-6. 95131(e) Error Triggering Re-Verification - Requirements for Verification Services

Comment: Section 95131(e) makes identification of an error a trigger for re-verification within 90 days by a different verification body. SoCal Gas and SDG&E appreciate the added language that provides ARB the ability to not require a full set-aside of emissions for minor errors. Additionally we request the ability to appeal an ARB audit finding that a verification statement failed, to the extent that the failure was due to circumstances beyond the reporting entity's reasonable control. To minimize ARB workload impact, these appeals could be handled through the regional district hearing boards.

Section 95131(e) If the Executive Officer finds a high level of conflict of interest existed between a verification body and a reporting entity, an error is identified, or an emissions data report that received a positive or qualified positive verification statement fails an ARB audit, the Executive Officer may set aside the positive or qualified positive verification statement issued by the verification body, and require the reporting entity to have the emissions data report re-verified

by a different verification body within 90 days. This paragraph applies to verification statements for emissions and product data. In instances where an error to an emissions data report is identified and determined by ARB to not affect the emissions or covered product data, the change may be made without a set aside of the positive or qualified positive verification statement. A reporting entity may appeal an ARB audit finding that a verification statement failed through a regional district hearing board. The hearing board will determine whether the verification failure was due to circumstances beyond the reporting entity's reasonable control. The appeal petition must be filed within 30 days of the negative ARB audit, with a hearing scheduled 30 days after the petition is filed. While the appeal is pending, the 90 day clock to obtain a new verification is to be stayed pending the outcome of the appeal.

[F 17.03d – SU]

Response: See response to comment H-4.

§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 Requirements for Verification Bodies

No comments were received on section 95133.

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

§95152 – Greenhouse Gases to Report

§95153 – Calculating GHG Emissions

P-1. 95153(g) Calculating GHG Emissions - Equipment and pipeline blowdowns

Comment: SoCalGas and SDG&E's distribution departments are required to report GHG emissions from equipment and pipeline blow downs under §95153(g). However, U.S. EPA 40 CFR 98 limits the reportable blow down volumes to fifty cubic feet and greater, while ARB's MRR has no minimis reporting volumes. Having no de minimus volume is difficult for all segments and for our distribution organization it theoretically includes the blow down of very small, very low-pressure services and other small low-pressure equipment Historically these equipment have been considered to have de minimis emissions; thus these blow downs activities are not currently recorded. It is not cost effective to estimate such small activities on an individual basis. SoCalGas and SDG&E request that the MRR include the U.S. EPA rule minimum reporting volume of 50 cubic feet.

[F 17.04a – SU]

Response: Staff has not proposed any amendments to section 95153(g). As such, the commenter's requested changes are beyond the scope of the current rulemaking. Therefore, ARB declines to make this change.

P-2. 95153(m) Calculating GHG Emissions - Compressors

Comment: Section 95153 (m) Centrifugal compressor venting delineates how one must calculate annual emissions of methane, carbon dioxide and nitrous oxide (when flared) from both wet seal and dry seal centrifugal compressor vents. Section 951539 (m)(6) applies to centrifugal compressors with a rated horsepower (hp) less than 250 hp and requires the use of Equation 22. The specified emission factors for methane (12,000,000 standard cubic feet per year per compressor) and carbon dioxide 530,000 standard cubic feet per year in Equation 22 are not appropriate for estimating emissions from dry seal compressors. The emission factors in Equation 22 match those in 40 CFR 98.233 (o) (7) for centrifugal compressor wet seal oil degassing vents and are not at all applicable to dry seals. Additionally, these emission factors appear to be based on 24-7, 365 days per year operation or 8,760 hours per year. It is more appropriate to use an emission factor that has a time factor for actual hours of operation for dry seals.

Why compressor dry seals are not comparable to centrifugal compressor wet seal oil degassing vents is very obvious when one considers the definitions in 40 CFR 98.6 of Subpart W versus those in the MRR as follows:

- Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO2 from escaping to the atmosphere. This definition is almost identical to that in the MRR, although the word operates was changed by ARB to operate. Operates is the correct verb as it refers to "a series" which is singular and not to the plural "rings."

- Centrifugal compressor dry seal emissions mean natural gas or CO2 released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case. This definition is left out of the MRR in its entirety. When the description of dry vent emissions is compared to the wet seal degassing vent emissions as described fully in U.S. EPA's definition below, the questionability of why emissions from wet seal and dry seal centrifugal compressors are calculated identically is apparent.

- Centrifugal compressor wet seal degassing vent emissions means emissions that occur when the high pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO2. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tank, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere. The last three sentences have been left off the MRR definition masking the stark differences between dry seal and wet seal compressor emissions.

Dry seal compressors vents have much lower emissions than wet seal compressor degassing vents, and the emissions should not be calculated using the same emission factors. Doing so adopts a technically flawed methodology that does not reflect the major difference in how emissions from of these two types of seals actually occur.

[F 17.04b – SU]

Response: Staff has not proposed any amendments to section 95153(m)(6). As such, the commenter's requested changes are beyond the scope of the current rulemaking. Therefore, ARB staff declines to make this change.

§95156 – Additional Data Reporting Requirements

P-3. Comment:

The New Term "Processes" in Section 95156(c) Must Be Defined

The proposed revisions to the MRR include the following changes to Section 95156(c) (the most recent proposed changes are shown using double strikethrough and underline):

The operator of a natural gas liquid fractionating facility, ~~or~~ a natural gas processing facility, or an onshore petroleum and natural gas production facility with a ~~gas plant~~ natural gas processing plant that ~~produces~~ processes less than 25 MMscf per day must report the annual production of the following natural gas liquids in barrels corrected to 60 degrees Fahrenheit:

***

As described in earlier comments, Inergy is a natural gas liquids processor. As a natural gas liquids processor, Inergy does not "produce" natural gas from underground sources. The proposed replacement of "produces" with "processes" in Section 95156(c) appropriately recognizes this distinction, and the change should be adopted. It is important that CARB now take the next step and define "processes".

Natural gas processers may undertake a wide range of activities, some of which may include the processing of natural gas, and others which may not. Inergy previously explained that it processes, stores, or distributes or resells unfractionated gas liquids delivered by others, typically natural gas producers. Processing may be minor, such as drying or odorizing, or it may involve fractionating and reforming natural gas liquids. With respect to the latter category, Inergy may process or fractionate the unfractionated liquids into a variety of "products", such as methane, ethane, propane, butane, mixed butane, normal butane, isobutene, and natural gasoline. After processing, natural gas generally is delivered by pipeline to a public utility, and liquids are shipped to customers by truck and rail. Inergy may also store gas and liquids for customers, and, from time-to-time, Inergy may purchase a "product" and resell it. Other natural gas liquids processors may undertake similar activities, or they may operate differently.

In light of the potential wide range of activities that natural gas processing facilities may perform, it is critical that CARB clearly and precisely define "processes" and related terms for purposes of reporting requirements in the MRR. For example, are drying, odorizing, or blending considered "processes" for which production must be reported under proposed revised Section 95156(c)? Reporting entities and third-party verifiers should not have to speculate what might be considered a "process" under the MRR, and risk having to prepare multiple iterations of a report or rejection by CARB. Clarification is needed to avoid increased costs and inefficiencies for reporting entities, third-party verifiers, and CARB staff, and to ensure reporting requirements are equitably applied to all natural gas processors across a level playing field.

Inergy recommends that CARB further modify the MRR to define "processes" as used in Section 95156(c), or commit to working with stakeholders to develop clear, published guidance identifying the specific "processes" to which CARB is referring.

[F 14.01 – IWC]

Response: ARB staff appreciates the support of the 15-day modifications of section 95156(c). ARB staff believes that the industry segment description of onshore natural gas processing in section 95150(a)(3) of the MRR defines a wide range of processing types, and therefore declines to make the suggested changes. In order to ensure the reporting requirements are met, ARB staff is committed to working with this commenter to understand the requirements of section 95156(c) and specifically work with them on which aspect of their processing they should include in their final emissions data report.

§95157 – Records that Must Be Retained

P-4. 95157(19). Activity Data Reporting Requirements

Comment: WSPA previously noted issues with this section2 and ARB has amended the text. However, the new text requires reporting the volume of gas produced in MMBtu. This is an error as the units should be in Mscf.

Recommendation: Amend 95157 (H) to read: "H) Annual volume of associated gas produced (Mscf) using thermal enhanced oil recovery and non-thermal enhanced oil recovery. This data is subject to conformance check only." [F 10.17 – WSPA]

Response: See response to comment I-9.

P-5. 95157(c) Activity Data Reporting Requirements

Comment: Section 95157(c)(14)(C)(2) for reciprocating compressors in not operating, depressurized mode, a reporting entity is to report the "Facility operator emission factor for isolation valve emissions in not operating mode, depressurized mode in cubic feet per hour." There is no calculation for a "facility operator emission factor" in §95153(n); thus, it is not clear what value is to be reported. We appreciate clarification of this issue. [F 17.04c – SU]

Response: Staff has not proposed any amendments to sections 95153(n) and 95157(c)(14)(C)(2). As such, the commenter's requested changes are beyond the scope of the current rulemaking. Therefore, ARB staff declines to make this change. Notwithstanding this, ARB staff is committed to working with reporting entities to ensure they understand the reporting requirements and may issue clarifying guidance if needed.

Other Comments Received:

P-6. Training Materials Request

Comment: TransAlta requests that ARB updates their training materials for verifiers to align with the recent regulatory changes. TransAlta requests that ARB make this material publicly available well in advance of the 2014 reporting deadline. [F 04.06 – TA]

Response: ARB staff, as part of updating the Cal e-GGRT reporting tool and getting ready for the next reporting year, plans to update training materials for reporting entities and verifiers. To the extent feasible, this material will be updated prior to the 2014 reporting deadline for electric power entities.

P-7. Comment:

CARB must update and publish technical guidance for verifiers

WPTF understands that CARB staff provides ongoing training sessions and guidance materials for accredited verifiers, including technical guidance applicable to individual categories of reporting entities. Yet the only information that is publicly available on the website is dated 2011 and corresponds to the 2007 version of the MRR.[3]

Given that CARB has significantly revised the regulation and issued several rounds of substantive guidance since that time, CARB should update both the general guidance and training materials, as well as that specific to individual categories of reporting entities (e.g. electric power entities). Because this guidance effectively determines how the verification process is conducted, we believe that it should also be made available to reporting entities. We therefore request that CARB make all verification guidance and training materials, including technical guidance for specific categories of reporting entities, publicly available on its website well in advance of the 2014 reporting deadline.

[F 07.04 – WPTF]

Response: See response to comment P-6 [F 04.06].

P-8. Comment: Guidance Regarding Implementation of the Amendments Should be Provided. There are a number of changes – some minor, others more significant – that go into effect once the regulatory amendments are approved. Not only will reporting entities need to be conversant with the revisions, but verifiers will also need to know how to apply new rules in order to timely complete the mandated verification. Because some of these issues are necessarily complex, M-S-R urges CARB to provide updated guidance to reporting entities. Further, CARB should develop detailed guidance for verifiers to ensure that all parties have a full and comprehensive understanding of the myriad technical aspects of the Regulation and the recent amendments to it. [F 09.04 – MSR]

Response: See response to comment P-6 [F 04.06].

V. Peer Review

Health and Safety Code Section 57004 sets forth requirements for peer review of identified portions of rulemakings proposed by entities within the California Environmental Protection Agency, including ARB. Specifically, the scientific basis or scientific portion of a proposed rule may be subject to this peer review process. For this rulemaking, which is a set of regulatory amendments to the existing reporting regulation, ARB determined that the rulemaking at issue does not contain a scientific basis or scientific portion subject to peer review, and thus no peer review as set forth in Section 57004 was or needed to be performed.