California Environmental Protection Agency

Air Resources Board

PUBLIC MEETING AGENDA

September 20, 2012

LOCATION:
Air Resources Board
Byron Sher Auditorium, Second Floor
1001 I Street
Sacramento, California 95814
http://www.calepa.ca.gov/EPAbldg/location.htm

This facility is accessible by public transit. For transit information, call (916) 321-BUSS, website: http://www.sacrt.com
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September 20, 2012
9:00 a.m.

DISCUSSION ITEMS:

Note: The following agenda items may be heard in a different order at the Board meeting.

Agenda Item #

12-6-1: Public Meeting to Hear an AB 32 Update

Staff will update the Board on the implementation of the Cap-and-Trade Regulation.

12-6-2: Public Hearing to Consider Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions and Conforming Amendments to the Definition Sections of the AB 32 Cost of Implementation Fee Regulation and the Cap-and-Trade Regulation

Staff will present minor revisions to the Air Resources Board's (ARB) regulation for the mandatory reporting of greenhouse gas (GHG) emissions as well as conforming definitional changes in the AB 32 Cost of Implementation Fee Regulation and the Cap-and-Trade Regulation. These revisions are necessary to harmonize, to the extent feasible, with the U.S. EPA national GHG reporting rule and ensure sufficient accuracy and completeness in reported emissions and product data to support California's Cap-and-Trade Program.

12-6-3: Public Meeting to Present Updates from the California Fuel Cell Partnership and the Plug-In Electric Vehicle Collaborative on Zero Emission Vehicle Infrastructure Readiness

Staff will introduce two presentations by the California Fuel Cell Partnership and Plug-In Electric Vehicle Collaborative on zero emission vehicle infrastructure development in preparation for zero emission vehicle commercialization.

CLOSED SESSION

The Board will hold a closed session, as authorized by Government Code section 11126(e), to confer with, and receive advice from, its legal counsel regarding the following pending or potential litigation:

Pacific Merchant Shipping Association v. Goldstene, U.S. District Court (E.D. Cal. Sacramento), Case No. 2:09-CV-01151-MCE-EFB.

POET, LLC, et al. v. Goldstene, et al., Superior Court of California (Fresno County), Case No. 09CECG04850; plaintiffs appeal, Court of Appeal No. F064045.

Rocky Mountain Farmers Union, et al. v. Goldstene, U.S. District Court (E.D. Cal. Fresno), Case No. 1:09–CV–02234–LJO–DLB; interlocutory appeal, U.S. Court of Appeal, Ninth Circuit Nos. 09-CV-02234 and 10-CV-00163.

American Fuels and Petrochemical Manufacturing Associations, et al. v. Goldstene, et al., U.S. District Court (E.D. Cal. Fresno) Case No. 1:10-CV-00163-AWI-GSA; interlocutory appeal, U.S. Court of Appeal, Ninth Circuit Nos. 09-CV-02234 and 10-CV-00163.

Association of Irritated Residents, et al. v. California Air Resources Board, Superior Court of California (San Francisco County), Case No. CPF-09-509562.

Association of Irritated Residents, et al. v. U.S. E.P.A., 2011 WL 310357 (C.A.9), (Feb. 2, 2011).

California Dump Truck Owners Association v. California Air Resources Board, U.S. District Court (E.D. Cal. Sacramento) Case No. 2:11-CV-00384-MCE-GGH.

Engine Manufacturers Association v. California Air Resources Board, Sacramento Superior Court, Case No. 34-2010-00082774.

Citizens Climate Lobby and Our Children's Earth Foundation v. California Air Resources Board, San Francisco Superior Court, Case No. CGC-12-519554.

OPPORTUNITY FOR MEMBERS OF THE BOARD TO COMMENT ON MATTERS OF INTEREST

Board members may identify matters they would like to have noticed for consideration at future meetings and comment on topics of interest; no formal action on these topics will be taken without further notice.

OPEN SESSION TO PROVIDE AN OPPORTUNITY FOR MEMBERS OF THE PUBLIC TO ADDRESS THE BOARD ON SUBJECT MATTERS WITHIN THE JURISDICTION OF THE BOARD

Although no formal Board action may be taken, the Board is allowing an opportunity to interested members of the public to address the Board on items of interest that are within the Board's jurisdiction, but that do not specifically appear on the agenda. Each person will be allowed a maximum of three minutes to ensure that everyone has a chance to speak.

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IF YOU HAVE ANY QUESTIONS, PLEASE CONTACT THE CLERK OF THE BOARD:
1001 I Street, 23rd Floor, Sacramento, California 95814
(916) 322-5594
ARB Homepage: www.arb.ca.gov

SPECIAL ACCOMMODATION REQUEST

Special accommodation or language needs can be provided for any of the following:
- An interpreter to be available at the hearing;
- Documents made available in an alternate format or another language;
- A disability-related reasonable accommodation.

To request these special accommodations or language needs, please contact the Clerk of the Board at (916) 322-5594 or by facsimile at (916) 322-3928 as soon as possible, but no later than 7 business days before the scheduled Board hearing. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Comodidad especial o necesidad de otro idioma puede ser proveído para alguna de las siguientes:
- Un intérprete que esté disponible en la audiencia.
- Documentos disponibles en un formato alterno u otro idioma;
- Una acomodación razonable relacionados con una incapacidad.

Para solicitar estas comodidades especiales o necesidades de otro idioma, por favor llame a la oficina del Consejo al (916) 322-5594 o envíe un fax a (916) 322-3928 lo más pronto posible, pero no menos de 7 días de trabajo antes del día programado para la audiencia del Consejo. TTY/TDD/Personas que necesiten este servicio pueden marcar el 711 para el Servicio de Retransmisión de Mensajes de California.

SMOKING IS NOT PERMITTED AT MEETINGS OF THE CALIFORNIA AIR RESOURCES BOARD

California Environmental Protection Agency

Air Resources Board

PUBLIC MEETING AGENDA

LOCATION:
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INDEX

September 20, 2012

TITLE 17. CALIFORNIA AIR RESOURCES BOARD

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

The Air Resources Board (ARB or Board) will conduct a public hearing at the time and place noted below to consider amendments to California's existing Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations, section 95100 et seq.), which was developed pursuant to requirements of the California Global Warming Solutions Act of 2006. The Board will also consider amendments to the definition sections of the AB 32 Cost of Implementation Fee regulation (title 17, California Code of Regulations, section 95200 et seq.) and the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms regulation (title 17, California Code of Regulations, section 95800 et seq.) made to conform with the proposed amendments to the mandatory reporting regulation.

DATE: September 20, 2012

TIME: 9:00 a.m.

PLACE: California Environmental Protection Agency
Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This item may be considered at a two-day meeting of the Board, which will commence at 9:00 a.m., September 20, 2012, and may continue at 8:30 a.m., September 21, 2012. This item may not be considered until September 21, 2012. Please consult the agenda for the meeting, which will be available at least 10 days before September 20, 2012, to determine the day on which this item will be considered.

INFORMATIVE DIGEST OF PROPOSED ACTION AND POLICY STATEMENT OVERVIEW

Sections Affected: Proposed amendments to sections 95101, 95102, 95103, 95104, 95105, 95111, 95112, 95113, 95114, 95115, 95119, 95120, 95121, 95122, 95123, 95130, 95131, 95132, 95133, 95150, 95151, 95152, 95153, 95154, 95155, 95156, 95157, 95202, and 95802, title 17, California Code of Regulations. Proposed adoption of new section 95158, title 17, California Code of Regulations.

Documents Incorporated by Reference:

Oil and Gas and Sulfur Operations in the Outer Continental Shelf; 30 Code of Federal Regulations (CFR) Part 250, Subpart C (July 1, 2011 Edition);

Year 2008 Gulfwide Emission Inventory Study (GOADS); U.S. Department of the Interior, OCS Study, BOEMRE 2010-045 (December 2010);

Alternative Work Practice for Monitoring Equipment Leaks; 40 CFR Part 60, Subpart A (July 1, 2011 Edition);

Method 21 – Determination of Volatile Organic Compound Leaks; 40 CFR Part 60, Appendix A-7 (July 1, 2011 Edition);

Regulation of Fuels and Fuel Additives, 40 CFR Part 80.40, 40 CFR Part 80.41, and 40 CFR Part 80.27 (July 1, 2011 Edition).

Background:

In 2006, the Legislature passed and Governor Schwarzenegger signed the California Global Warming Solutions Act of 2006 (Assembly Bill 32 (AB 32); Stats. 2006, chapter 488). In AB 32, the Legislature declared that global warming poses a serious threat to the economic well-being, public health, natural resources, and environment of California. AB 32 created a comprehensive, multi-year program to reduce greenhouse gas (GHG) emissions in California, with the overall goal of restoring emissions to 1990 levels by the year 2020.

Regulation for the Mandatory Reporting of Greenhouse Gas Emissions

One of the requirements of AB 32 is that ARB must adopt a greenhouse gas reporting regulation. To comply with this requirement, the Board approved the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (reporting regulation) at its December 2007 Board meeting. The reporting regulation became effective on January 2, 2009. All relevant documents for the 2007 rulemaking, including the final regulation, are available at: http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm.

Over the past four years, ARB staff has implemented the California greenhouse gas reporting program established by the reporting regulation. Under the program, over 600 facilities and entities annually submit to ARB their greenhouse gas emissions data reports, which are verified as accurate and complete by ARB-accredited third-party verifiers. Information about the program can be found at: http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm.

At its December 2010 public hearing, the Board approved amendments to the reporting regulation to support the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (title 17, CCR, section 95800 et seq.) (cap-and-trade regulation) data requirements, harmonize to the extent feasible with the United States Environmental Protection Agency's (U.S. EPA) Final Rule on Mandatory

Reporting of Greenhouse Gases (rule), and align with the Western Climate Initiative (WCI) reporting structure. The amendments to the reporting regulation became effective on January 1, 2012. All relevant documents for the 2010 rulemaking, including the amended regulation, are available at: http://www.arb.ca.gov/regact/2010/ghg2010/ghg2010.htm.

Since the approval of the 2010 amendments to the reporting regulation, there have been several changes and updates that affect the calculation methods in the regulation. In late 2011, U.S. EPA updated its rule for Petroleum and Natural Gas Systems (Title 40, Code of Federal Regulations, Part 98, Subpart W), correcting and updating several emissions calculation methods. ARB staff has also identified minor clarifications that are needed to ensure the reporting elements in the reporting program are accurate and reflect their intended purpose. Finally, ARB staff identified reporting elements that need to be added to the reporting program to ensure effective implementation of the cap-and-trade program.

ARB staff is proposing targeted revisions to ARB's current reporting regulation necessary to align California's GHG emissions reporting with the changes discussed above, to streamline and avoid duplicate GHG reporting, and to continue to provide the highest quality data needed to support California's cap-and-trade regulation.

AB 32 Cost of Implementation Fee and California Cap-and-Trade Regulations

AB 32 authorized ARB, through Health and Safety Code section 38597, to adopt a schedule of fees to be paid by sources of GHG emissions to support the costs of carrying out AB 32 measures. At the Board's September 25, 2009 hearing, the Board directed ARB's Executive Officer to finalize the AB 32 Cost of Implementation Fee Regulation (fee regulation). The Executive Officer subsequently adopted these regulations and submitted them to the California Office of Administrative Law (OAL). The regulations were approved by OAL and became legally effective on July 17, 2010. The fee regulation requires sources of GHG emissions to pay a regulatory fee which is to be used to support the costs of implementing AB 32 measures. More information on the fee regulation may be found at: http://www.arb.ca.gov/cc/adminfee/adminfee.htm.

AB 32 also authorized ARB to adopt a market-based compliance mechanism in its regulations. From 2009 through 2011, ARB staff developed the overall options for a market-based mechanism program design and development. ARB staff conducted extensive public consultation, including more than 40 public meetings, to discuss and share ideas with the general public and key stakeholders on the appropriate structure of the cap-and-trade regulation. The cap-and-trade regulation, which went into effect on January 1, 2012, provides a fixed limit on GHG emissions from the sources responsible for about 85 percent of the state's total GHG emissions. The cap-and-trade regulation reduces GHG emissions by applying a declining aggregate cap on GHG emissions, and creates a flexible compliance system through the use of tradable instruments (allowances and offset credits).

In order to ensure consistency in terminology across the reporting regulation, fee regulation, and cap-and-trade regulation, revisions, additions, and deletions were made in the definition sections of the fee regulation and the cap-and-trade regulation to conform to the proposed amendments to the reporting regulation described below. Note that the conforming definitional changes herein are distinct from those cap-and-trade regulation amendments approved by the Board in June 2012.

A description of the proposed action follows. The proposed amendments were initially presented in an informal discussion draft released on May 29 and subsequently discussed at a public workshop held May 30, 2012. Additional informal discussion drafts for electric power entity definitions and the proposed amendments to subarticle 5 were released on June 14th and 15th, respectively, and discussed in webinars held on June 19, 22, and 29, 2012. Staff considered the informal comments provided during and after these meetings in crafting the staff proposal.

Description of the Proposed Regulatory Action, Objectives, and Benefits

The purpose of the proposed amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions is to: (1) harmonize to the extent feasible with the U.S. EPA national greenhouse gas reporting requirements, (2) ensure sufficient accuracy and completeness in reported emissions and product data to support California's cap-and-trade program, (3) make clarifications to improve the understanding and transparency of reporting requirements and methodologies, and (4) ensure consistency in terminology used in the reporting regulation, fee regulation, and cap-and-trade regulation. Anticipated benefits of the proposed revisions include improved clarity for reporting entities as to their reporting and verification obligations, more accurate GHG emissions estimates from corrected or updated emissions calculation methods and emission factors, improved clarity to support the statewide greenhouse inventory program and continued robust methods for reporting emissions and product data in order to support ARB's cap-and-trade regulation. These benefits may also result in indirect benefits to the health and welfare of California residents, worker safety, and the state's environment by ensuring that the state has an accurate inventory of GHG emissions to support programs which will reduce emissions and directly improve the health and welfare of California residents, worker safety, and the state's environment.

To achieve these goals, amendments to the current reporting regulation are being proposed. Under this proposal, most of the current reporting requirements of the reporting regulation remain the same. Subarticle 5 has substantial text additions because ARB staff is proposing to add the reporting requirements and calculation methods from the U.S. EPA rule for Petroleum and Natural Gas Systems (Subpart W) directly into the reporting regulation rather than incorporate the federal rule by reference. For reporting entities, this improves clarity of the requirements and reduces confusion when ARB and U.S. EPA requirements differ. Overall though, the reporting requirements for Petroleum and Natural Gas Systems are substantially the same as in the current reporting regulation, with the exception of amended emission factors and calculation methods based on recent U.S. EPA updates.

The following paragraphs describe the revisions that are included in this regulatory action to the reporting regulation. Conforming definitional amendments to the fee regulation and the cap-and-trade regulation are also described.

Subarticle 1. General Requirements for Greenhouse Gas Reporting

Applicability and Cessation of Reporting Requirements. Instead of incorporating the applicability requirements and cessation of reporting requirements from U.S. EPA's rule by reference, ARB staff is proposing to set forth directly the text from the U.S. EPA rule in the mandatory reporting regulation. These additions will improve clarity for reporting entities in determining whether they are subject to the regulation. Additional clarifications were made in the applicability section to indicate that electricity generating units not subject to 40 CFR Part 75 are subject to mandatory reporting under the general stationary combustion category and in the cessation of reporting section to clarify requirements for electric power entities.

Process Emissions. The reporting requirements for abbreviated reporters (facilities with less than 25,000 metric tons of carbon dioxide equivalents, $MTCO_2e$) were modified to include the reporting of process emissions in emissions data reports and to determine the 10,000 $MTCO_2e$ threshold for abbreviated reporting. The purpose of this amendment is to obtain more complete emissions data and to track any effect of emissions "leaking" from facilities with emissions greater than 25,000 $MTCO_2e$ into activities by abbreviated reporter facilities. In the current reporting regulation, process emissions are calculated and reported only by facilities with emissions greater than 25,000 $MTCO_2e$. An analysis by ARB staff, which is included in Chapter VI of the ISOR, indicates that this modification of the abbreviated reporting requirements will affect only a small number of facilities in California.

Measurement Accuracy Requirements. The measurement accuracy requirements have been clarified in these amendments. Specifically, the intent of the requirements has been explicitly included in section 95103(k) and a field accuracy assessment option has been added to reduce the risk of data losses going back more than one year. The currently enacted version of the reporting regulation includes requirements for the frequency of meter calibrations, which, depending on the approach, is about every three years. If a meter fails calibration, it is possible that data collected by that meter in the past three years could be voided. In order to ensure that data losses due to failed calibrations do not result in a substantial loss of data for a multi-year time period, staff has proposed including an optional field accuracy assessment which would allow reporting entities to perform an annual test to ensure the meter is still calibrated accurately. Additionally, staff has proposed amendments to clarify that if a meter fails calibration, a reporter may also demonstrate by other means that the meter was indeed calibrated for a portion of the time since the last calibration.

Product Data Verification Requirements. The current reporting regulation requires product data to be verified and subject to material misstatement assessments for each single product data component. In order to be consistent with the reporting requirements for emissions data, ARB staff has proposed removing the verification requirement for each single product data and instead basing material misstatement assessments on the sum of all product components. This reduces the risk of a single minor product causing a material misstatement for all products that would be within the five percent accuracy requirement and invalidating their ability to receive allocations under the cap-and-trade program. This would be similar to how covered emissions data is verified and would be called covered product data. Additional information on product data verification is also covered in subarticle 4.

Other. Modifications, clarifications and additional definitions have been added to subarticle 1. The definitional changes were made to support the proposed regulatory changes identified in this notice. The majority of the definitional changes relate to amendments to subarticle 5 (petroleum and natural gas systems), because the calculation methods were added into the body of the regulation instead of being incorporated by reference. In order to ensure consistency in terminology between the reporting regulation and ARB's fee regulation and cap-and-trade regulation, conforming revisions, additions, and deletions are also proposed for the definition sections of both of those regulations (section 95202 of the fee regulation and section 95802 of the cap-and-trade regulation). In addition, the proposed amendments would require facilities to inform ARB whether they meet the statutory definition of a small business to assist in leakage analysis. Further modifications are proposed to correct internal references, as well as spelling and punctuation errors.

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

Electric Power Entities. The two main amendments proposed for electric power entity reporting are clarifications to the requirements for asset-controlling suppliers and clarifications on the data used to generate the emission factors for specified sources and asset-controlling suppliers.

Asset-Controlling Supplier Requirements. The asset-controlling supplier application and reporting process has been clarified in these amendments. Previously, the asset-controlling supplier application process was ambiguous in certain areas, which generated many questions from stakeholders. Clarifications to the asset-controlling supplier application process and proposed language on the reporting requirements alleviate these concerns. Specifically, staff is proposing to clarify that if an entity chooses to seek asset-controlling supplier designation, it would need to report and verify annually, submit all necessary information to calculate their system emission factor, and in the case of an adverse verification statement, lose their status as an asset-controlling supplier, which includes their ARB-calculated system emission factor. Additionally, the amendments would remove the system emission factor for Bonneville Power Administration from the reporting regulation. Instead, ARB would publish any approved and calculated supplier system emission factors on the ARB website. This change was made to ensure consistency in the treatment of asset-controlling supplier emission factors. In the event that an asset-controlling supplier fails to report and verify, the unspecified default emissions rate is applicable to emissions reports.

Emission Factor Calculation Data Vintage. Proposed language was added to indicate the vintage (i.e., year) of data for calculating the emission factors for specified sources and for asset-controlling suppliers. For example, for specified sources, a 2012 emission data report will be based on 2012 transaction data and 2011 emission factor data. However for an asset-controlling supplier, a 2012 emission data report will be based on 2012 transaction data and 2010 emission factor data. The additional lag time for the asset-controlling supplier is needed to ensure that power entities have advanced knowledge of the reporting and verification status of the asset-controlling supplier and the appropriate system emission factor before they use that factor in their emissions data reporting. All 2012 emission data reports would be submitted in 2013. ARB plans to post asset-controlling supplier emission factors to the ARB website prior to the end of each calendar year.

Other Electric-Power Entity Issues. Clarifications to wheeled power and the first point of receipt and final point of delivery were made. An additional reporting requirement for reporting renewable energy credit (REC) serial numbers was added to section 95111(g)(1)(M) to ensure accurate tracking of the RECs as they pertain to the RPS adjustment.

Unit Aggregation. ARB staff has proposed several clarifications to the unit aggregation requirements. In the current reporting regulation, certain electricity generating units did not have aggregation options that could streamline reporting. The proposed amendments include additional options and conditions for unit aggregation and other emission sources.

Importers of Compressed Natural Gas and Liquefied Natural Gas. In the current regulation, importers of compressed natural gas and liquefied natural gas were omitted. ARB staff is proposing amendments to include those entities in the mandatory reporting regulation.

Other. Minor clarifications to the product data reporting requirements were made for the refinery, hydrogen, and rare earths manufacturing sectors. Calcined coke was added to the product data reporting requirements because it is a product that is used to determine the allocation of allowances in the cap-and-trade regulation. Hydrogen production was modified to split out hydrogen gas and liquid hydrogen. In addition, clarifications to the transportation fuels and natural gas suppliers were made to improve clarity in the applicability rationale for these sectors. These amendments are proposed to clarify the requirements for these sectors with regards to the point of regulation.

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.

Verification Services for Facilities Under 25,000 $MTCO_2e$. ARB staff has proposed deleting language from section 95130 that subjects facilities that may have significantly less than 25,000 $MTCO_2e$ of annual emissions to acquiring verification services. The intent of requiring verification services is to ensure that reporting entities with over 25,000 $MTCO_2e$ of emissions, or facilities that are electric power entities or that opt-in, report accurately and transparently and to provide for increased assurance for data used in the cap-and-trade program. It was not the intent of ARB staff to require small facilities subject to the zero emission threshold reporting requirements of section 95101, who do not have a cap-and-trade compliance obligation, to obtain verification services if they are below 25,000 $MTCO_2e$.

Other. Proposed amendments to the regulation include definitional additions for sector specialty categories in the accreditation section, clarifications to the material misstatement calculation for product data, as discussed above, and minor clarifications to the conflict of interest section. The conflict of interest changes improve upon the clarity of how verification services that can be performed by verification bodies outside of the state are to be assessed.

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

Directly Include Calculation Methods and Reporting Requirements. In the current version of the reporting regulation, the calculation methods and reporting requirements from the U.S. EPA rule were incorporated by reference. However, since adoption of the reporting regulation, the petroleum and natural gas systems section of the U.S. EPA rule have changed considerably. In order to improve stability of the methods and requirements for the California reporting program in the face of potential U.S. EPA changes, and improve clarity within the regulatory text, staff is proposing amendments to add all the calculation methods, definitions, and reporting requirements directly in subarticle 5 (as opposed to simply incorporating the U.S. EPA rule by reference). While the number of pages associated with this change appears substantial, the actual methodological differences from the U.S. EPA rule, and the current ARB regulation, which incorporated those U.S. EPA rule requirements, are minimal.

Onshore Petroleum and Natural Gas Production Definition. In the current regulation, the onshore petroleum and natural production industry segment definition includes the phrase: "associated with a well pad." The amended regulation maintains this definition as opposed to updating to U.S. EPA's new term: "associated with a single well pad." The reason for maintaining the existing approach is to ensure a sufficient breadth of emissions is covered for onshore petroleum and natural gas productions for the cap-and-trade regulation.

Other. The proposed amendments include modifications to the best available monitoring methods (BAMM). The proposed amendments would specifically allow the use of BAMM for certain calculation methods through the collection of 2012 data. However, in 2013, the use of BAMM will no longer be permitted. Lastly, modifications to the U.S. EPA rule also occurred in the following instances: additional industry segments are covered for pipeline and equipment blowdowns and flare stack emissions reporting; and a more stringent method for reporting of leaker emissions for onshore petroleum and natural gas production. These proposed changes were made because the U.S. EPA methods were not rigorous enough to support the needs of the cap-and-trade program and the statewide greenhouse gas inventory program.

Complete details are provided in the proposed regulation and the Initial Statement of Reasons, which are available at:
http://www.arb.ca.gov/regact/2012/ghg2012/ghg2012.htm.

CONSISTENCY AND COMPATIBILITY WITH EXISTING STATE REGULATIONS

Staff does not believe the proposed regulation is inconsistent or incompatible with existing state regulations.

MANDATED BY FEDERAL LAW OR REGULATIONS

This regulation is not mandated by federal law or regulations.

COMPARABLE FEDERAL REGULATIONS

As mentioned previously, the U.S. EPA requires mandatory GHG reporting (*Mandatory Reporting of Greenhouse Gases; Final Rule*. 40 CFR Parts 86, 87, 89, 90, 94, and 98. United States Environmental Protection Agency. October 30, 2009). Staff does not believe the proposed regulation is inconsistent with existing federal law. In fact, this proposed amended regulation was developed to minimize, to the greatest extent possible, any redundant State and federal reporting, while also ensuring that ARB is collecting the necessary additional information required by California's various GHG programs, including the cap-and-trade regulation, fee regulation, and the statewide GHG inventory.

AVAILABILITY OF DOCUMENTS

ARB staff has prepared a Staff Report: Initial Statement of Reasons (ISOR) for the proposed regulatory action, which includes a summary of the economic and environmental impacts of the proposal. The ISOR is entitled: "Staff Report: Initial Statement of Reasons for Rulemaking: Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions and Conforming Amendments to the Definition Sections of the AB 32 Cost of Implementation Fee Regulation and the Cap-and-Trade Regulation."

Copies of the ISOR and the full text of the proposed regulatory language may be accessed on ARB's website listed below, or may be obtained from the Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814, or by calling (916) 322-2990 within the 45 days prior to the scheduled hearing on September 20, 2012.

AVAILABILITY OF FINAL STATEMENT OF REASONS

Upon its completion, a Final Statement of Reasons (FSOR) will be available and copies may be requested from the agency contact persons in this notice, or may be accessed on ARB's website listed below.

AGENCY CONTACT PERSONS

Inquiries concerning the substance of the proposed regulation may be directed to the designated agency contact persons, Dr. David Edwards, Manager of ARB Climate Change Reporting Section, Planning and Technical Support Division at (916) 323-4887, or Ms. Joelle Hulbert Howe, Air Pollution Specialist, at (916) 322-6349.

Further, the agency representative and designated back-up contact persons to whom nonsubstantive inquiries concerning the proposed administrative action may be directed are Ms. Lori Andreoni, Manager, Board Administration & Regulatory Coordination Unit (916) 322-4011, or Ms. Trini Balcazar, Regulations Coordinator, (916) 445-9564. The Board staff has compiled a record for this rulemaking action, which includes all the information upon which the proposal is based. This material is available for inspection upon request to the contact persons.

INTERNET ACCESS

This notice, the ISOR and all subsequent regulatory documents, including the FSOR, when completed, are available on ARB's website for this rulemaking at: http://www.arb.ca.gov/regact/2012/ghg2012/ghg2012.htm.

FISCAL IMPACT AND ECONOMIC IMPACT ASSESSMENT/ANALYSIS

The determinations of the Board's Executive Officer concerning the costs or savings necessarily incurred by public agencies, private persons and businesses in reasonable compliance with the proposed regulatory action are presented below. A detailed assessment of the fiscal and economic impacts of the proposed regulation is included in the Initial Statement of Reasons for this regulatory item. The cost summary described below is focused on the reporting regulation; the cap-and-trade and the fee regulations do not incur any costs for their conforming definitional changes.

COSTS TO PUBLIC AGENCIES AND TO BUSINESSES AND PERSONS AFFECTED

The Executive Officer has made an initial determination that the proposed regulatory action would not have a significant statewide adverse economic impact directly affecting businesses, including the ability of California businesses to compete with businesses in other states, or on representative private persons. Because most facilities affected by the proposed revisions are already subject to the regulation, they will only have a small incremental cost to comply with the revised rule provisions. There will be no noticeable change in employment, business creation, elimination or expansion, or business competitiveness in California due to the proposed revisions.

Costs to Businesses and Private Individuals

In developing this regulatory proposal, ARB staff evaluated the potential economic impacts on representative businesses and determined that there would be a potential net cost saving on businesses directly affected. Staff estimates that the total net saving is $1.2 million over the course of 10 years for all affected entities, which can be further broken down to a saving of $871,000 over 10 years for private businesses and a saving of $356,600 for local government entities. The proposed revisions are not expected to impact state government entities and private persons. Chapter VI of the ISOR for the proposed regulation includes additional data on the estimated costs to facilities.

Facilities that are subject to the federal and California GHG reporting regulations regardless of emission level (i.e., electricity generation facilities subject to the federal Acid Rain Program and certain industries with process emissions) but that have total facility emissions of less than 25,000 $MTCO_2e$ can expect to see a total net incremental cost saving of $1.2 million over the course of 10 years from the amendments due to the proposed exemption from third-party verification requirements. Facilities with process emissions that have combustion emissions of less than 25,000 $MTCO_2e$ are expected to incur a small incremental cost of up to $2,000 per facility per year for including process emissions in their GHG reports.

For importers of compressed natural gas and liquefied natural gas, the proposed amendments may result in a cost increase of $500-$2,000 per facility per year for requiring these facility types to report and verify those fuels. The incremental cost for the oil and gas sector is expected to be $259,000 over 10 years. Oil and gas facilities are expected to see an incremental cost increase of $50 to $2,000 per facility per year, depending on their industry segment and size. Oil and gas facilities in the other industry segments are expected to see an incremental cost ranging from a few hundred dollars to $2,000 per facility per year. State-wide, most of the incremental costs are borne by the oil and gas sector, accounting for 70%of the total state-wide costs among the cost-incurring sectors. The incremental costs to the other industry sectors make up the remaining 30% of the state-wide costs.

Small Businesses

The Executive Officer has determined, pursuant to title 1, CCR, section 4, that the proposed regulatory action will affect small businesses. Staff estimates that approximately 3 small businesses may be affected in California. Some of these small business entities that have emissions less than 25,000 $MTCO_2e$ will see a cost saving from the exemption of third-party verification requirements. Other facilities may incur marginal incremental cost to comply with the proposed requirement to include process emissions in their GHG reports.

Costs to State Government and Local Agencies

The proposed regulatory action will reduce costs to some local agencies. Like their counterparts in the private sector, publicly owned electricity generating facilities with total facility emissions of less than 25,000 $MTCO_2e$ are expected to see a cost saving from the exemption of verification requirements. ARB anticipates that 9 electricity generating facilities operated by local government entities will see a collective saving of $356,600 over 10 years. Because the regulatory requirements apply equally to all reporting categories and unique requirements are not imposed on local agencies, the Executive Officer has determined that the proposed regulatory action imposes no costs on local agencies that are required to be reimbursed by the state pursuant to part 7 (commencing with section 17500), division 4, title 2 of the Government Code, and does not impose a mandate on local agencies that is required to be reimbursed pursuant to Section 6 of Article XIII B of the California Constitution. In addition, there are no other nondiscretionary costs or savings imposed upon local agencies.

Pursuant to Government Code sections 11346.5(a)(5) and 11346.5(a)(6), the Executive Officer has determined that the proposed regulatory action would not create costs or savings in federal funding to the state, or costs or mandate to any school district whether or not reimbursable by the state pursuant to Part 7 (commencing with section 17500), division 4, title 2 of the Government Code.

Adoption of the proposed revisions has no additional fiscal impact on ARB. No change in staffing level is needed to administer the program under the revised rule. ARB fiscal expenses needed for integrating the proposed amendments into the existing reporting systems are already accounted for in the current operational budget that was proposed in the previous amendment to the rule.

STATEMENT OF THE RESULTS OF THE ECONOMIC IMPACT ASSESSMENT PREPARED PURSUANT TO GOVERNMENT CODE SEC. 11346.3(b)

In accordance with Government Code section 11346.3, the Executive Officer has determined that the proposed regulatory action would not result in a creation or elimination of jobs within the State of California, or the creation or elimination of existing businesses within the State. Creation of jobs had already occurred at the inception of the reporting program in 2008 as it created the need for technical support for developing GHG emissions estimates, providing laboratory and other services, and providing emission verification services. These existing jobs should be retained, and staff does not anticipate noticeable job creation due to the smaller scope of this regulatory action.

Anticipated benefits of the proposed revisions include improved clarity for reporting entities as to their reporting and verification obligations, more accurate GHG emissions estimates from corrected or updated emissions calculation methods and emission factors, improved clarity to support the statewide greenhouse inventory program and continued robust methods for reporting emissions and product data in order to support ARB's cap-and-trade regulation. These benefits may also result in indirect benefits to the health and welfare of California residents, worker safety, and the state's environment by ensuring that the state has an accurate inventory of GHG emissions to support programs which will reduce emissions and directly improve the health and welfare of California residents, worker safety, and the state's environment.

In accordance with Government Code sections 11346.3(c) and 11346.5(a)(11), the Executive Officer has found that the reporting requirements of the regulation which apply to businesses are necessary for the health, safety, and welfare of the people of the State of California.

A detailed assessment of the economic impacts of the proposed regulatory action can be found in the ISOR.

SIGNIFICANT STATEWIDE ADVERSE ECONOMIC IMPACT DIRECTLY AFFECTING BUSINESS, INCLUDING ABILITY TO COMPETE

The Executive Officer has made an initial determination that the proposed regulatory action would not have a significant statewide adverse economic impact directly affecting businesses, including the ability of California businesses to compete with businesses in other states, or on representative private persons.

ALTERNATIVES

Before taking final action on the proposed regulatory action, the Board must determine that no reasonable alternative considered by the Board or that has otherwise been identified and brought to the attention of the Board, would be more effective in carrying out the purpose for which the action is proposed or would be as effective 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 provision of law. Since the proposed amendments are made to the existing reporting regulation, fee regulation, and cap-and-trade regulation, and given that these proposed amendments do not have a significant adverse fiscal or economic impact, no alternatives, other than one in which no regulatory amendments would be made and ones in which the specific amendments to various sector requirements are compared to harmonization with the applicable U.S. EPA rule requirements, were considered. These alternatives are fully described in Chapter III of the ISOR.

ENVIRONMENTAL ANALYSIS

In accordance with ARB's certified regulatory program, California Code of Regulations, title 17, sections 60006 through 60007, and the California Environmental Quality Act, Public Resources Code section 21080.5, ARB has conducted an analysis of the potential for significant adverse and beneficial environmental impacts associated with the proposed regulatory action. The environmental analysis of the proposed regulatory action can be found in Chapter IV of the ISOR.

SUBMITTAL OF COMMENTS

Interested members of the public may present comments relating to this matter orally or in writing at the hearing, and comments may also be submitted by postal mail or electronic submittal before the hearing. The public comment period for this regulatory item will begin on August 6, 2012. To be considered by the Board, written submissions not physically submitted at the hearing must be submitted on or after August 6, 2012, and received **no later than 12:00 noon, September 19, 2012**, and must be addressed to the following:

Postal Mail: Clerk of the Board, Air Resources Board
1001 I Street, Sacramento, California 95814

Electronic submittal: http://www.arb.ca.gov/lispub/comm/bclist.php

You can sign up online in advance to speak at the Board meeting when you submit an electronic board item comment. For more information go to: http://www.arb.ca.gov/board/online-signup.htm

Please note that under the California Public Records Act (Gov. Code, § 6250 et seq.), your written and verbal comments, attachments, and associated contact information (e.g., your address, phone, email, etc.) become part of the public record and can be released to the public upon request.

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. The Board encourages members of the public to bring to the attention of staff in advance of the hearing any suggestions for modification of the proposed regulatory action.

Additionally, the Board requests but does not require that persons who submit written comments to the Board reference the title of the proposal in their comments to facilitate review.

STATUTORY AUTHORITY AND REFERENCES

This regulatory action is proposed under that authority granted in Health and Safety Code, sections 38510, 38530, 38560, 38562, 38564, 38570, 38571, 38580, 38597, 39600, 39601, 39607, 39607.4, and 41511. This action is proposed to implement, interpret and make specific sections 38501, 38505, 38510, 38530, 38560.5, 38564, 38565, 38570, 38580, 38597, 39600, 39601, 39607, 39607.4, and 41511 of the Health and Safety Code.

HEARING PROCEDURES

The public hearing will be conducted in accordance with the California Administrative Procedure Act, title 2, division 3, part 1, chapter 3.5 (commencing with section 11340) of the Government Code.

Following the public hearing, the Board may adopt the regulatory language as originally proposed or with nonsubstantial or grammatical modifications. The Board may also adopt the proposed regulatory language with other modifications if the text as modified is sufficiently related to the originally proposed text that the public was adequately placed on notice that the regulatory language as modified could result from the proposed regulatory action. In the event that such modifications are made, the full regulatory text, with the modifications clearly indicated, will be made available to the public for written comment at least 15 days before it is adopted.

The public may request a copy of the modified regulatory text from ARB's Public Information Office, Air Resources Board, 1001 I Street, Visitors and Environmental Services Center, First Floor, Sacramento, California, 95814, (916) 322-2990.

SPECIAL ACCOMMODATION REQUEST

Special accommodation or language needs can be provided for any of the following:

- An interpreter to be available at the hearing;
- Documents made available in an alternate format (i.e., Braille, large print, etc.) or another language;
- A disability-related reasonable accommodation.

To request these special accommodations or language needs, please contact the Clerk of the Board at (916) 322-5594 or by facsimile at 916) 322-3928 as soon as possible, but no later than 10 business days before the scheduled Board hearing. TTY/TDD/Speech to Speech users may dial 711 for the California Relay Service.

Comodidad especial o necesidad de otro idioma puede ser proveído para alguna de las siguientes:

- Un intérprete que esté disponible en la audiencia.

- Documentos disponibles en un formato alterno (por decir, sistema Braille, o en impresión grande) u otro idioma.
- Una acomodación razonable relacionados con una incapacidad.

Para solicitar estas comodidades especiales o necesidades de otro idioma, por favor llame a la oficina del Consejo al (916) 322-5594 o envíe un fax a (916) 322-3928 lo más pronto posible, pero no menos de 10 días de trabajo antes del día programado para la audiencia del Consejo. TTY/TDD/Personas que necesiten este servicio pueden marcar el 711 para el Servicio de Retransmisión de Mensajes de California.

CALIFORNIA AIR RESOURCES BOARD

James N. Goldstene
Executive Officer

Date: July 24, 2012

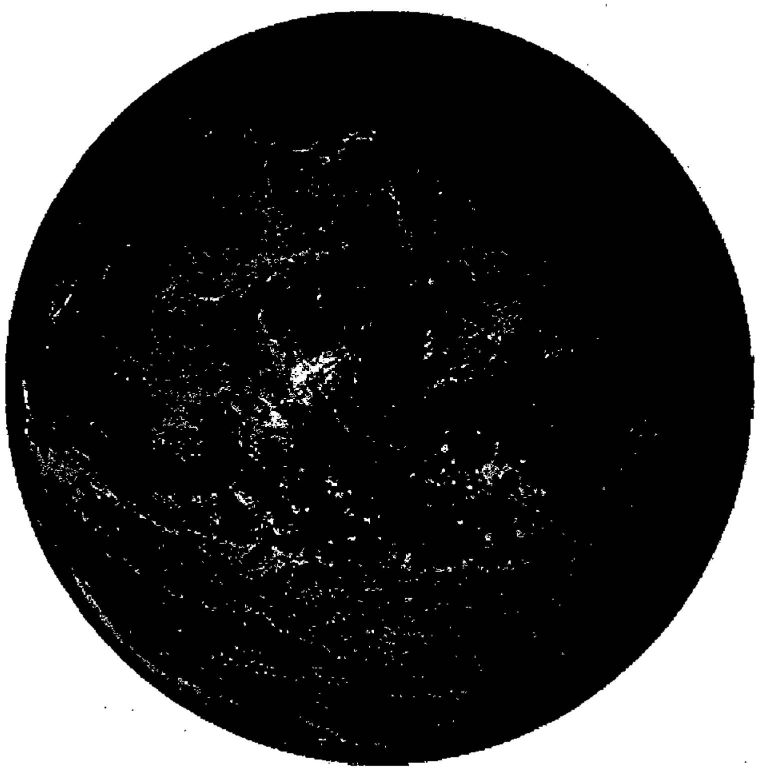
The energy challenge facing California is real. Every Californian needs to take immediate action to reduce energy consumption. For a list of simple ways you can reduce demand and cut your energy costs, see our website at www.arb.ca.gov.

California Environmental Protection Agency

Air Resources Board

STAFF REPORT: INITIAL STATEMENT OF REASONS FOR RULEMAKING

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



Planning and Technical Support Division
Emission Inventory Branch

August 1, 2012

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State of California

AIR RESOURCES BOARD

Staff Report: Initial Statement of Reasons
for Proposed Rulemaking

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

Date of Release: August 1, 2012
Scheduled for Consideration: September 20, 2012

Location:
California Air Resources Board
Byron Sher Auditorium
1001 I Street
Sacramento, California 95814

This staff report has been reviewed by the staff of the California Air Resources Board and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Air Resources Board, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

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STAFF REPORT: INITIAL STATEMENT OF REASONS

PUBLIC HEARING TO CONSIDER

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

Air Resources Board Meeting
September 20, 2012 at 9:00 a.m.
Air Resources Board
Cal/EPA Headquarters
Byron Sher Auditorium
1001 I Street
Sacramento, CA 95814

This item will be considered at a meeting of the Board, which will commence at 9:00 a.m. on September 20, 2012.

For those unable to attend the meeting in person, a live video webcast will be available beginning at 9:00 a.m. on September 20, 2012, at http://www.calepa.ca.gov/broadcast

This staff report and related materials are available for download from the Air Resources Board's Internet site at:
http://www.arb.ca.gov/regact/2012/ghg2012/ghg2012.htm.
In addition, written copies may be obtained from the Board's Public Information Office, 1001 I Street, 1st Floor, Environmental Services Center, Sacramento, California 95814, (916) 322-2990.

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Questions
If you have questions concerning this report, please contact:

Dr. David Edwards
Manager,
Climate Change Reporting Section
Phone: (916) 323-4887
Email: dedwards@arb.ca.gov

or

Ms. Joelle (Hulbert) Howe
Air Pollution Specialist,
Climate Change Reporting Section
Phone: (916) 322-6349
Email: jhulbert@arb.ca.gov

Prepared By:

Planning and Technical Support Division
Greenhouse Gas Emission Inventory Branch
Climate Change Reporting Section
Emissions Quality Assurance and Verification Section

Reviewed by
Office of Legal Affairs
Planning and Technical Support Division
Stationary Source Division

Acknowledgments

This staff report was prepared with the assistance and support of many individuals within the Air Resources Board. In addition, staff would like to acknowledge the assistance and cooperation of many private individuals and organizations, whose contributions throughout the regulation development process have been invaluable.

TABLE OF CONTENTS

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EXECUTIVE SUMMARY

Air Resources Board staff is proposing to amend the Regulation for the Mandatory Reporting of Greenhouse Gas (GHG) Emissions (reporting regulation) along with conforming amendments to the definition sections of the AB 32 Cost of Implementation Fee Regulation (fee regulation) and the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation (cap-and-trade regulation). The reporting regulation was originally developed pursuant to the California Global Warming Solutions Act of 2006 (Assembly Bill 32 or the Act), and adopted by the Air Resources Board (ARB) in December 2007. In December 2010, the Board adopted amendments to the reporting regulation in order to harmonize with the GHG reporting requirements of the United States Environmental Protection Agency (U.S. EPA), support California's cap-and-trade program, and align with the Western Climate Initiative (WCI) reporting structure. Since the Board's December 2010 action, the U.S. EPA has made additional revisions to their GHG reporting rule and corrected errors, updated emission factors and modified other reporting requirements. In addition, ARB staff has also identified other omissions and inconsistencies in the regulatory requirements that need clarification to ensure the reported GHG data are accurate and fully support the cap-and-trade program, as well as California's statewide greenhouse gas emission inventory and other AB 32 programs.

This staff report presents the ARB staff's proposal to amend the reporting regulation and make conforming definition changes to the fee regulation and cap-and-trade regulation. The staff report discusses the reasons for the proposed amendments and the potential impacts from the regulatory changes. The proposed amendments represent minor but necessary revisions to the current reporting regulation. Staff is not proposing major changes to GHG reporting requirements nor adding reporting obligations for new industrial sectors. The changes correct or clarify reporting requirements necessary for submittal of complete and accurate emission data reports, and add or modify data elements for product data reporting necessary to support the cap-and-trade program. The changes are also necessary to align California's GHG emissions reporting with the changes and updates discussed above, to streamline and avoid duplicate GHG reporting, and to continue to provide the high quality of data needed to support a market-based cap-and-trade program. Other updates proposed and discussed in this staff report include changes to conform the definition sections of both the cap-and-trade and fee regulations to the amendments in the reporting regulation to ensure consistent application of each rule.

Background

AB 32 requires California to cut greenhouse gas emissions to 1990 levels by 2020 and to develop a comprehensive strategy to reduce dependence on fossil fuels, stimulate investment in clean and efficient technologies, and improve air quality and public health. AB 32 also requires the Air Resources Board to adopt regulations for the mandatory reporting of greenhouse gas emissions in order to monitor and enforce compliance with ARB's GHG emissions reductions actions, including market-based compliance mechanisms. The ARB adopted a market-based, cap-and-trade program in October

2011. AB 32 also requires ARB to review existing and proposed international, federal, and state greenhouse gas emission reporting programs and make reasonable efforts to promote consistency among the programs.

Objectives of the Proposed Regulation Amendments

ARB staff has proposed amendments to the regulations in order to:

- Continue alignment of the GHG reporting requirements with the U.S. EPA, to the extent feasible, by making corrections and updates to emission estimation methods, emission factors, and reporting requirements;
- Continue to support California's cap-and-trade program by clarifying product data collection requirements, product data verification procedures, and adding additional product data reporting;
- Ensure that reported GHG emissions data is accurate and complete in order to support California's GHG reduction programs, including the statewide GHG emission inventory; and
- Modify the definitions in the cap-and-trade and the fee regulations to conform to the proposed mandatory reporting definition amendments.

The proposed amendments to the mandatory reporting regulation do not change the overall reporting structure. No new sectors were added. All sectors which currently incorporate U.S. EPA's rule requirements (from 40 CFR Part 98) by reference continue to reference the U.S. EPA requirements, except for the Petroleum and Natural Gas Systems sector, as described below. The verification requirements remain constant, although staff is proposing that verification for all reporting entities emitting less than 25,000 metric tons of carbon dioxide equivalents ($MTCO_2e$) would no longer be required. Instead, the proposed amendments improve upon, clarify, and add to the existing requirements. For the Petroleum and Natural Gas Systems sector, the regulatory text previously incorporated by reference from the U.S. EPA rule is proposed to be written directly into the regulation. While this amendment results in a seemingly large amount of changes, it does not alter existing reporting requirements, except in cases where methods were updated or changes were made to reflect the more rigorous data needed for the cap-and-trade or other AB 32 programs. ARB staff believes that adding in the U.S. EPA rule for petroleum and natural gas systems in the reporting regulation aids in understanding the regulatory requirements and will improve the accuracy of reporting. Product data elements and requirements were added to ensure facilities have the opportunity to receive their full allotment of allocations under the cap-and-trade program.

Overview of the Proposed Amendments

Tables ES-1and ES-2 provide summaries of the key amendments proposed to the regulations. More complete descriptions of the proposed amendments are found in the succeeding chapters of this report.

Table ES-1
Summary of Proposed Regulatory Amendments to the Mandatory Reporting Regulation

Topic/Sector	*Proposed Regulatory Amendment*
Petroleum and natural gas systems	♦ U.S. EPA GHG reporting rule language written directly into the reporting regulation to improve clarity and certainty for reporting entities in this sector ♦ Added additional requirements for some industry segments to ensure complete reporting
Electric Power Entities (EPEs)	♦ Clarified the asset-controlling supplier application process ♦ Removed explicit asset-controlling supplier designation for Bonneville Power Administration (BPA) and default BPA system emission factor ♦ Clarified the vintage (year) of the data used to calculate the emission factors for specified sources and asset-controlling suppliers
Measurement accuracy requirements	♦ Added a voluntary field accuracy assessment in order to lower the risks of lost data between required three-year meter calibrations
Product data requirements	♦ Clarified and expanded product data reporting requirements for petroleum and natural gas systems ♦ Clarified product data verification requirements ♦ Added calcined coke to refinery products ♦ Added additional requirements for natural gas fractionators who produce natural gas liquids

Topic/Sector		Proposed Regulatory Amendment
Verification		♦ Amended third-party verification requirements to only apply to reporting entities emitting 25,000 $MTCO_2e$ or more. Previously, certain reporting entities were required to report and verify their emissions data reports regardless of their emissions level; this modification results in more equitable verification treatment for all entities emitting less than 25,000 $MTCO_2e$, and in cost savings as described in Chapter VI ♦ Clarified product data verification requirements
Definition changes		♦ Updated definitions to clarify reporting requirements in current and proposed amendments
Other		♦ Added requirements for imported compressed natural gas (CNG) and liquefied natural gas (LNG) ♦ Added reporting of process emissions for abbreviated reporters ♦ Clarified the fuel supplier reporting requirements ♦ Modified the unit aggregation for electricity generating units ♦ Made corrections to typographical errors

Table ES-2
Summary of Proposed Regulatory Amendments to the Cap-and-Trade and AB 32 Cost of Implementation Fee Regulations

Definition changes		♦ Updated definitions to conform with proposed changes made in the mandatory reporting regulation

Economic Impact Analysis

The proposed amendments will result in a net cost savings of $1.2 million for private industry and local government as described in Chapter VI.

Staff Recommendation

Staff recommends that the Board adopt the proposed amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions and the conforming amendments to the definition sections of the AB 32 Cost of Implementation Fee Regulation and the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation.

I. INTRODUCTION AND BACKGROUND

This staff report presents proposed revisions to three interrelated regulations developed pursuant to the California Global Warming Solutions Act of 2006 (Assembly Bill 32, the Act). These include the:

- Regulation for the Mandatory Reporting of Greenhouse Gas (GHG) Emissions (reporting regulation).
- California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms (cap-and-trade regulation)
- AB 32 Cost of Implementation Fee Regulation (fee regulation)

The majority of proposed amendments and this staff report focus on the reporting regulation. However, to maintain consistency among the three regulations, staff is also proposing conforming amendments to those definitions also found in the cap-and-trade and fee regulations. Those conforming definition changes are also described within this staff report.

A. Overview of Prior Regulatory Actions

The Regulation for the Mandatory Reporting of Greenhouse Gas Emissions was originally developed pursuant to AB 32, and adopted by the Air Resources Board (ARB or Board) in December 2007 (ARB MRR 2007). In December 2010, ARB adopted substantial revisions to the original regulation to harmonize with the U.S. Environmental Protection Agency (U.S. EPA) federal mandatory GHG reporting requirements contained in title 40, Code of Federal Regulations (CFR), Part 98; to support a California greenhouse gas (GHG) cap-and-trade program; and to align with the Western Climate Initiative (WCI) reporting structure. These revisions became effective January 1, 2012. The full regulatory record and background for these two previous GHG reporting regulation rulemakings is available here:
http://www.arb.ca.gov/regact/2007/ghg2007/ghg2007.htm (ARB MRR 2007), and here:
http://www.arb.ca.gov/regact/2010/ghg2010/ghg2010.htm (ARB MRR 2010).

AB 32 also authorized ARB, through Health and Safety Code section 38597, to adopt a schedule of fees to be paid by sources of GHG emissions to support the costs of carrying out AB 32 activities. At the Board's September 25, 2009 hearing, the Board approved the AB 32 Cost of Implementation Fee Regulation (fee regulation). The fee regulation was approved by OAL and became legally effective on July 17, 2010 (COI 2010). More information on the fee regulation may be found at:
http://www.arb.ca.gov/cc/adminfee/adminfee.htm.

AB 32 also authorized ARB to adopt a market-based compliance mechanism to reduce GHG emissions. From 2009 through 2011, ARB staff developed the overall options for a market-based mechanism program design and development. ARB staff conducted extensive public consultation to discuss and share ideas with the general public and key stakeholders on the appropriate structure of the cap-and-trade regulation. Staff also met regularly with individual stakeholders to hear their concerns and recommendations. ARB staff collected public comments during each public workshop, which focused on key topics and program design components. The cap-and-trade regulation, first considered by the Board at its December 2010 hearing, provides a fixed limit on GHG emissions from the sources responsible for about 85 percent of the state's total GHG emissions (C&T 2011). The cap-and-trade regulation reduces GHG emissions by applying a declining aggregate cap on GHG emissions, and creates a flexible compliance system through the use of tradable instruments (allowances and offset credits). The cap-and-trade regulation went into effect January 1, 2012.

B. Objectives of the Proposed Regulatory Revisions

ARB staff has proposed amendments to the regulations in order to:

- Continue alignment of the GHG reporting requirements with the U.S. EPA, to the extent feasible, by making corrections and updates to emission estimation methods, emission factors, and reporting requirements;
- Continue to support California's cap-and-trade program by clarifying product data collection requirements, product data verification procedures, and adding additional product data reporting;
- Ensure that reported GHG emissions data is accurate and complete in order to support California's GHG reduction programs, including the statewide GHG emission inventory; and
- Modify the definitions in the cap-and-trade and the fee regulations to conform to the proposed mandatory reporting definition amendments.

The proposed amendments to the reporting regulation are necessary to further clarify reporting requirements, provide updates and corrections to emission estimation methods and emission factors, enhance metering accuracy requirements to improve data quality, and include additional or modified definitions reflecting the other modifications. The proposed amendments do not change the overall reporting structure of the reporting regulation and no new sectors were added to reporting. All sectors which currently incorporate U.S. EPA's rule requirements by reference continue to reference the U.S. EPA requirements, except for the Petroleum and Natural Gas Systems sector, as described below.

For the petroleum and natural gas systems sector, subarticle 5 of the regulation, the full regulatory requirements previously incorporated by reference from the U.S. EPA, are proposed to be written directly into the reporting regulation. ARB staff believes that this aids in the understanding of the regulatory requirements and improves the accuracy of reporting. In addition, requirements for petroleum and natural gas systems have been updated to include, to the extent feasible, the most current U.S. EPA requirements and other changes needed to improve accuracy and completeness. Specifically, the continued use of best available monitoring methods (BAMM) and the updated definition of onshore petroleum and natural gas production were not added into subarticle 5. Additionally, ARB staff proposed adding equipment and pipeline blowdowns and flare stack emissions reporting requirements for certain industry segments. A further discussion of the specific changes to subarticle 5 is discussed in Chapter VII, Summary and Rationale. Other proposed changes to the regulations are individually listed in Chapter VII.

C. Public Outreach

In developing the proposed amendments, staff initially presented ideas for amendments in an informal discussion draft released on May 29, which was subsequently discussed at a public workshop held on May 30, 2012 to receive comment and feedback from stakeholders. Additional informal discussion drafts for electric power entity definitions and proposed amendments to subarticle 5 (petroleum and natural gas systems sector) were released on June 14th and 15th, respectively, and discussed in webinars held on June 19, 22, and 29, 2012. Staff considered the informal comments provided during and after these meetings in crafting the staff proposal (ARB Workshop Comments 2012). In response to requests from stakeholders, staff held numerous one-on-one and small group teleconferences to discuss and refine the proposed revisions to the mandatory reporting regulation and the conforming definitional amendments in the fee regulation and cap-and-trade regulation.

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II. DESCRIPTION OF THE PUBLIC PROBLEM, PROPOSED SOLUTIONS TO THE PUBLIC PROBLEM AND RATIONALE SUPPORTING THE SOLUTIONS

In order to carry out the goals of AB 32, a robust and accurate greenhouse gas reporting program is necessary to track the emissions from reporting entities over time and to demonstrate progress in reducing GHG emissions. The proposed amendments to update calculation methods and emission factors utilized by the reporting program are necessary in order to continue to track the GHG emissions reduction goals of AB 32. With the proposed amendments to the reporting, cap-and-trade, and fee regulations described below, ARB staff intends to update the calculation methods, emission factors, and definitions to ensure the accurate tracking of AB 32 goals is achieved.

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

This chapter includes a discussion of proposed revisions to the regulations. Section A focuses on revisions to the reporting regulation. Section B highlights the conforming definition revisions to the cap-and-trade regulation. Section C discusses conforming definition revisions to the fee regulation. All changes are discussed in further detail in Chapter VII, Summary and Rationale.

A. Proposed Amendments to the Mandatory Reporting Regulation

This section includes a discussion of some of the key proposed revisions to the reporting regulation. At this time, ARB staff is not considering incorporating additional updates from U.S. EPA's reporting rule that affect sectors that ARB has excluded from the reporting.

1. General Revisions

Applicability and Cessation of Reporting. To help clarify the applicability requirements for California reporting entities, all industry sectors subject to reporting are listed in the general applicability section of the reporting regulation, rather than referring to the applicability requirements of the incorporated U.S. EPA GHG reporting rule. This change does not affect the numbers or types of entities subject to reporting.

To improve reporting consistency and to better assess potential leakage of GHG emissions from larger to smaller facilities to avoid reporting requirements, facilities that produce process emissions must now include those emissions in their applicability determinations and report the emissions under the proposed revisions. This is expected to affect less than five facilities.

Under the revisions, staff added suppliers of imported compressed natural gas or liquefied natural gas to the applicability requirements. Reporting was already required by California consignees of liquefied petroleum gas, so this revision will ensure equitable reporting by all fuel types. This is expected to affect five or fewer fuel suppliers, and does not add in any new reporting sector.

As with the applicability requirements, the proposed revisions will list the U.S. EPA reporting cessation requirements (USEPA MRR 2009-2010) in the reporting regulation, rather than simply incorporating them by reference. This revision clarifies the reporting cessation requirements and allows for minor sources to better understand their requirements to cease reporting when justified. Staff also clarified the cessation requirements for electric power entities, which are not subject to U.S. EPA reporting.

Abbreviated Reporting, Verification, and Product Data. Under the proposed revisions, facilities emitting between 10,000 to 25,000 metric tons of carbon dioxide equivalents ($MTCO_2e$) that are allowed to submit an abbreviated emissions data report must now report process emissions in addition to combustion emissions. This additional requirement provides the process emissions information necessary for leakage analysis, as required by the Act. The proposed revisions also streamline the reporting requirements for abbreviated reports by not requiring third-party verification for those reporters. Previously, some sectors were required to obtain third-party verification regardless of their emissions level. This revision will result in a cost saving to all sectors where reporting entities emit less than 25,000 $MTCO_2e$. (An analysis of this cost saving is included in Chapter VI, Economic Impacts).

Staff added text to clarify the reporting requirements for geothermal facilities, including the need to include information required in section 95112. This does not alter the existing requirements, but improves clarity for reporters.

Within the proposed revisions for product data, staff specified that the reporting accuracy requirements apply only to covered product data. Covered product data is product data used in the allocation of allowances under the cap-and-trade regulation, and is described in the newly added "covered product data" definition. This proposed amendment reduces the previous requirement that all product data, including any non-covered product data, had to meet the material misstatement requirements as part of third-party verification. This revision will provide a cost savings to reporters of product data.

A clarification was also made to section 95105(d)(6) regarding recordkeeping, to clarify that third-party verifiers need to evaluate electric power entities for the compliance obligation, RPS adjustment and qualified export reporting requirements.

Measurement Accuracy Requirements. The proposed amendments clarify the measurement accuracy requirements in the reporting regulation. Specifically, the intent of the requirements has been clarified in section 95103(k) and a voluntary field accuracy assessment has been added to reduce the risk of data losses from potential failed meter calibrations. The current reporting regulation includes requirements for the frequency of meter calibrations, which, depending on the approach, is about every three years. If a meter fails calibration, it is possible that data collected by that meter in the past three years could be voided. In order to ensure that data losses due to failed calibrations do not result in a substantial loss of data for a multi-year time period, staff has proposed including a voluntary field accuracy assessment which would allow reporting entities to perform an annual test to ensure the meter is still calibrated accurately. Additionally, staff has proposed amendments to clarify that if a meter fails calibration, a reporter may also use other means to demonstrate the meter accuracy between calibrations.

Unit Aggregation. Revisions are proposed to allow for data aggregation for electricity generating units in order to streamline reporting. In the current regulation, electricity generating units do not have unit aggregation options. Therefore, the proposed amendments also include additional options and conditions for unit aggregation and other emission sources.

Other Product Data Amendments. Revisions to the product data reporting requirements were made to the refinery and hydrogen production sectors. Calcined coke was added to the product data reporting requirements since it is a product used to determine the allocation of allowances in the cap-and-trade program. Hydrogen production was modified to split out hydrogen gas and liquid hydrogen. In addition, for transportation fuel suppliers, the proposed revisions now specifically list those fuels subject to reporting, rather than referencing a list incorporated by reference from the U.S. EPA reporting rule.

Electric Power Entities. The two main amendments proposed for electric power entity reporting are clarifications to the requirements for asset-controlling suppliers and clarifications on the data used to generate the emission factors for specified sources and asset-controlling suppliers.

Asset-Controlling Supplier Requirements: The proposed amendments will modify and clarify the asset-controlling supplier application and reporting process. In the current reporting regulation, the asset-controlling supplier application process is ambiguous in addressing requirements to maintain an asset-controlling supplier designation. The requirements have also been misinterpreted by certain stakeholders as applying only to Bonneville Power Administration. This has generated many questions from stakeholders. Clarifications to the asset-controlling supplier application process and proposed language on the reporting requirements alleviate these concerns. Specifically, the amendments clarify that asset-controlling suppliers must report and verify annually, submit all necessary information to calculate their system emission factor, and in the case of an adverse verification statement lose their status as an asset-controlling supplier, which includes their ARB-calculated system emission factor. Additionally, the system emission factor for Bonneville Power Administration as an asset-controlling supplier, which is directly listed in the current reporting regulation, is proposed to be removed but would be listed on ARB's web site with any other asset-controlling supplier designations. This change was proposed to ensure consistency in the treatment of asset-controlling suppliers and their ARB-calculated system emission factors. In the event that an asset controlling supplier fails to report and verify, the unspecified default emissions rate is applicable to emissions reports.

Emission Factor Calculation Data Vintage: Proposed language was added to indicate the vintage (i.e., year) of data for calculating the emission factors for specified sources and for asset-controlling suppliers. For example, for specified sources, a 2012 emission data report will be based on 2012 transaction data and 2011 emission factor data. However for an asset-controlling supplier, a 2012 emission data report will be based on 2012 transaction data and 2010 emission factor data. The additional lag time for the asset-controlling supplier is needed to ensure that power entities have advanced knowledge of the reporting and verification status of the asset-controlling supplier and are able to consider the appropriate system emission factor before they import electricity into California and to enable the use of that factor in their emissions data reporting. All 2012 emission data reports would be submitted in 2013. By the end of each calendar year, ARB plans to post asset-controlling supplier emission factors to the ARB website that will be applicable for reporting of each subsequent year's emissions. For example, by the end of 2013, ARB will post each asset-controlling supplier's emission factor to be used for 2014 emissions data reported in 2015.

Other: Staff is also proposing clarification amendments to wheeled power and the first point of receipt and final point of delivery. An additional reporting requirement for reporting renewable energy credits (REC) serial numbers was added to section 95111(g)(1)(M) to ensure accurate tracking of RECs as they pertain to the RPS adjustment.

Verification Requirements. Staff is proposing several clarifications for the verification of product data, including the requirement that only "covered product data" is subject to material misstatement assessments, and material misstatement assessments are conducted on total product data and not individual products. In addition to several minor general clarifications, staff has included revisions to clarify ARB's intent in the conflict of interest section, including changes to better describe how verification services that can be performed by verification bodies outside of the state are to be assessed. Finally, and as described previously, staff has proposed clarifications to specify that all entities emitting less than 25,000 $MTCO_2e$ would not need to obtain third-party verification.

2. Definition Revisions and Additions

General Clarifications and Additions. Existing definitions were clarified to minimize ambiguity. New definitions were added to support changes described in this staff report, such as additional product data reporting, the requirements for the petroleum and natural gas systems, and the inclusion of U.S. EPA requirements directly into the ARB regulation.

Electric Power Entity Definitions. Definitions associated with electric power entity reporting were added and modified to better define the source, the reporting requirements, and the data to be reported under the regulation.

Suppliers of Transportation Fuels Definitions. To clarify the reporting requirements, section 95121 of the regulation was updated to directly incorporate the fuels subject to reporting by transportation fuel suppliers. Previously, these fuels were identified by referencing separate tables in the U.S. EPA GHG Reporting Rule (Title 40, Code of Federal Regulations (CFR), Part 98). In listing the fuels directly in the ARB regulation, it was also necessary to define these fuels explicitly within the ARB regulation itself. As a result, about twenty additional definitions have been added, such as "premium grade gasoline," "ethane," and "rendered animal fat." These additional definitions are adapted verbatim (as near as possible) from the U.S EPA 40 CFR Part 98 regulation currently cited, and their inclusion does not change the existing reporting requirements. Each new definition is provided in section 95102 of the amended reporting regulation.

3. Subarticle 5 – Petroleum and Natural Gas Systems

Include all Calculation Methods and Reporting Requirements. In the current reporting regulation, the calculation methods and reporting requirements for petroleum and natural gas systems were incorporated by reference from the U.S. EPA rule. However, since adoption of the reporting regulation, U.S. EPA has made considerable changes to the petroleum and natural gas systems section of their rule. In order to improve clarity and certainty of the methods and requirements for the California reporting program, the proposed amendments include, to the extent feasible, all the most recent U.S. EPA calculation methods, definitions, and reporting requirements directly in subarticle 5 of the reporting regulation. While the number of pages associated with this change is substantial, the actual reporting requirement changes from the current reporting regulation are small.

Onshore Petroleum and Natural Gas Production Definition. In the current regulation, the onshore petroleum and natural gas production industry segment definition requires reporting of emissions "associated with a well pad." ARB staff is proposing no change to this definition as opposed to updating to U.S. EPA's new rule term, "associated with a single well pad." The reason for staying with the current approach was to require reporting of the full breadth of emissions from onshore petroleum and natural gas productions to support the cap-and-trade program.

Other. Modifications to the best available monitoring methods (BAMM) were made as well as some method improvements for various calculations. The proposed amendments would specifically allow the use of BAMM for certain calculation methods through the collection of 2012 data. However, beginning in 2013, the use of BAMM will no longer be permitted. Lastly, some of the methods proscribed in the U.S. EPA rule were replaced with more stringent methods and some of the requirements were extended to other industry segments. This added stringency is necessary because the U.S. EPA methods were not rigorous enough to support the needs of the cap-and-trade program and the statewide greenhouse gas inventory program.

B. Proposed Amendments to the Cap and Trade Regulation

Definition Revisions and Additions. In order to ensure consistency in terminology across the reporting regulation, fee regulation, and cap-and-trade regulation, revisions, additions, and deletions were made in the definition section of the cap-and-trade regulation to conform to the proposed amendments of the reporting regulation. No other changes have been proposed to the cap-and-trade regulation in this rulemaking action.

C. Proposed Amendments to the Cost of Implementation Fee Regulation

Definition Revisions and Additions. In order to ensure consistency in terminology across the reporting regulation, fee regulation, and cap-and-trade regulation, revisions, additions, and deletions were made in the definition section of the fee regulation to conform to the proposed amendments of the reporting regulation. No other changes have been proposed to the fee regulation in this rulemaking action.

III. SUMMARY OF RECOMMENDED BOARD ACTION AND SUMMARY OF ALTERNATIVES

Staff is proposing the amendments to the reporting regulation to continue harmonization with U.S. EPA on GHG emissions reporting methods and requirements, to the extent feasible, and to support the cap-and-trade program through the reporting of complete and robust GHG emissions data. Staff is also proposing conforming amendments to the definition sections of the AB 32 Cost of Implementation Fee Regulation and the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation. Staff is recommending that the Board accept the revisions to all three regulations, as proposed.

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

Performance standards were considered but are not feasible under AB 32 which requires rigorous and consistent statewide emissions reporting. These core requirements of the AB 32 reporting program do not lend themselves to the application of flexible performance standards.

The first alternative that staff considered was a "no regulatory change" alternative, meaning that reporting entities would continue to operate pursuant to the requirements and definitions of the current reporting regulation. The consequence of this "no regulatory change" alternative would mean that reporters would not be able to benefit from the many updates and corrections made to emission estimation methods and emission factors. Most of the updates and corrections are based on changes made by U.S. EPA to their GHG reporting rule. Since the reported data would not be accurate, the data would not help ARB fulfill its responsibility to maintain the statewide GHG emission inventory. Without the proposed changes to product data requirements, some reporters would not be able to submit product data that enables them to receive allowance allocations under the cap-and-trade program. Finally, the amendments relieve some reporters with the lower emissions level, including local governments, from verification requirements and those reporters would not benefit from this cost savings. For these reasons, ARB staff chose to reject this alternative.

ARB staff also considered alternatives for each major proposed change to the reporting regulation. Each proposed amendment was evaluated against all reasonable alternatives, including, where applicable, a "no action" alternative and a "harmonization with U.S. EPA" alternative. A "no action" alternative would mean no specific change would be made. A "harmonization with U.S. EPA" alternative would mean that ARB would use U.S. EPA's specific rule requirement, if one exists.

A full discussion of alternatives considered for the proposed rule changes is provided below. Sections A through G focus on the alternatives to the reporting regulation and Section H is devoted to discussing alternatives to the proposed conforming definition amendments for all three regulations.

A. Summary of Proposed Board Action and Alternatives to: Metering/ Measurement Device Field Accuracy Assessment Requirements -- Section 95103(k)

ARB staff proposes to include in section 95103(k) a voluntary annual field accuracy assessment (FAA). The FAA will provide GHG reporting entities with the option to assess and document that flow meters and other measurement devices are operating within the required ± 5 percent accuracy range in years between required device calibrations. This proposal is intended to provide options for GHG reporting entities to minimize the risk of data loss associated with a failed calibration event. Since the assessment is voluntary, individual facilities can determine their own level of risk based on their unique operations and experiences. This represents the lowest cost alternative. ARB staff considered the following alternatives to the proposed voluntary FAA:

No Action Alternative.
The current rule requires that flow meters and other measurement devices measuring covered emissions or covered product data be calibrated at least once during each three year compliance period. These requirements provide a good foundation for ensuring GHG reporting program data integrity, however complications may arise in the instance that a meter or other measurement device fails a calibration. Under the current rules, should a device fail calibration, the operator must prove by other means that the data has continually met the ± 5% accuracy requirement going back to the last successful calibration. Given that calibrations will normally occur every three years, a reporting entity would be required to prove data quality going back multiple years in the event of a failed calibration. Failure to demonstrate data accuracy within 5% could result in the invalidation of the data for up to three years. The proposed voluntary FAA provides a mechanism that can be used by the operator to minimize the risk of data loss by assessing and documenting on an annual basis that the device is maintaining accuracy. This decreases the chance that a device will fail a calibration, and ensures that data will not have to be proven accurate going back longer than one year since the last successful FAA. The "No Action" alternative does not provide adequate mitigation options for failed calibration, does not provide a method for reporters to lower their meter failure risk without a costly and full meter calibration, and would result in a higher burden of time and resources on ARB staff, verifiers, and GHG reporting entities should a device fail a calibration.

Harmonization with U.S. EPA Alternative.
The U.S. EPA GHG reporting rule does not have a mechanism for mitigating risk of data loss in the event of a failed calibration; therefore the analysis for this alternative is identical to the "No Action" alternative addressed above.

Mandatory Annual Field Accuracy Assessment (FAA).
ARB staff considered proposing a mandatory FAA for all flow meters and other measurement devices measuring covered emissions and covered product data. This alternative proposal would ensure a high level of meter accuracy by requiring operators to annually assess and document device accuracy within the ± 5% accuracy range. However, this option imposed substantial costs on facilities and limited the ability of the operator to perform a facility level risk assessment based on internal expertise with the metering devices and systems. Because the FAA is intended to be a mechanism to manage data risk, ARB staff chose to reject the mandatory FAA alternative.

Mandatory Annual Full Calibration.
ARB staff considered proposing mandatory annual calibration of all flow meters and other measurement devices measuring covered emissions and covered product data. This alternative proposal would ensure optimum meter accuracy by requiring operators to annually perform a full calibration in accordance with the calibration procedures documented in section 95103(k). This option imposed the most significant costs to facilities, and went above and beyond U.S. EPA requirements as well as the original equipment manufacturer (OEM) recommendations for many types of flow meters and other measurement devices. Due to these concerns, and given the ability of reporting entities to mitigate risks and still provide accurate data using a voluntary FAA, ARB staff chose to reject the mandatory annual calibration alternative.

B. Summary of Proposed Board Action and Alternatives to: Process Emissions Reporting for Abbreviated Reporters -- Section 95103(a)

ARB staff proposes to include process emissions when evaluating the 10,000 metric ton applicability threshold, and require that process emissions be calculated and reported for specified industrial sectors emitting less than 25,000 metric tons of CO_2e per year. Added costs from the proposed changes are expected to be small per facility, and only 3-4 facilities are estimated to be affected by the proposed change. ARB staff considered the following alternatives to the proposed revision:

No Action Alternative.
In the current version of the mandatory GHG reporting regulation, only stationary combustion emissions are considered when assessing the applicability threshold for abbreviated reporting (in the 10,000-25,000 $MTCO_2$e emission range). Additionally, facilities in this range are not currently required to calculate and report process emissions. The lack of process emissions reporting by facilities with combustion emissions between 10,000-25,000 $MTCO_2$e would limit the ability to detect changes in process emissions in this group and to identify potential emissions leakage from

facilities with emissions greater than 25,000 $MTCO_2e$. Because added costs from the proposed changes are expected to be small per facility, and only 3 to 4 facilities are estimated to be affected by the proposed change, ARB staff has rejected the "no action" alternative in order to better assess leakage of certain facilities with process emissions.

Harmonization with U.S. EPA Alternative.
The U.S. EPA GHG reporting rule does not require GHG reporting below 25,000 $MTCO_2e$. Therefore, the analysis for this alternative is identical to the "No Action" alternative addressed above.

C. Summary of Proposed Board Action and Alternatives to: Reporting requirements for LNG/CNG Importers – Section 95122

ARB staff proposes to add reporting requirements for importers of Liquefied Natural Gas (LNG) and Compressed Natural Gas (CNG). LNG and CNG imports were unintentionally left out of the current reporting regulation. The inclusion of the proposed imported LNG/CNG reporting requirements ensures completeness of reporting for all forms of imported natural gas. ARB staff considered the following alternatives to the proposed revision:

No Action Alternative.
Currently, a fuel supplier importing natural gas in the form of LNG or CNG for use in California would not have to report emissions associated with the combustion of this fuel. While natural gas is not typically imported in the form of LNG or CNG, ARB staff believes that the omission of natural gas imported as LNG/CNG in the current ARB regulation for mandatory GHG reporting is not sufficiently rigorous to support a cap-and-trade program for GHG emissions. As such, ARB staff chose not to maintain the current reporting requirements without making necessary revisions.

Harmonization with U.S. EPA Alternative.
The U.S. EPA GHG reporting rule does not address imports of natural gas in LNG/CNG form; therefore the analysis for this alternative is identical to the "No Action" alternative addressed above.

D. Summary of Proposed Board Action and Alternatives to: Changes to Petroleum and Natural Gas Systems, Subarticle 5

ARB staff proposes to incorporate the calculation methods for petroleum and natural gas systems directly into the reporting regulation, slightly modify some of reporting requirements to ensure the GHG statewide inventory needs are met, and modify the product data requirements to support the cap-and-trade program. While ARB has strived to minimize changes from the U.S. EPA Subpart W to limit additional reporting requirements for Subarticle 5 reporters, the proposed changes ensure that the needs of the California reporting program and cap-and-trade program are met, while ensuring stability and clarity of the reporting requirements in the face of potential U.S. EPA changes to the federal reporting rule.

No Action Alternative.
Currently, the petroleum and natural gas systems section references the U.S. EPA reporting rule as of April 2011. In the past year, the U.S. EPA has made multiple updates and corrections to the petroleum and natural gas systems section of the federal GHG reporting rule. A "no action" alternative would mean California petroleum and natural gas systems facilities would not be able to benefit from the more accurate factors and methods. In addition, without the proposed changes to product data requirements, some reporters would not be able to submit product data that enables them to receive allowance allocations under the cap-and-trade program. By not changing this section, ARB staff believes that the cap-and-trade program, and specifically the allocation of allowances, would rely on inaccurate emissions data. In addition, the California reporting program would be lagging behind the U.S. EPA rule, by not using the most up-to-date equations and methods. As a consequence, ARB staff has rejected the "no action" alternative.

Harmonization with U.S. EPA Alternative.
The ARB staff proposal to update and correct emission factors and emissions estimation methods does harmonize with the U.S. EPA. However, since the U.S. EPA reporting rule was designed to collect data adequate for emissions inventory purposes only, and not a more rigorous cap-and-trade program, the U.S. EPA rule lacks the more rigorous emission estimation methods and the additional product data necessary to support California's cap-and trade program. For these reasons, some reporting regulation methods were modified to ensure that cap-and-trade quality emissions data is reported. For instance, ARB staff has limited reporters' choice of methods to three of the four U.S. EPA calculation methods for Acid Gas Removal Vent emissions. The fourth, and least rigorous, method was examined and determined not to generate cap-and-trade quality data. While the majority of changes were made to harmonize with the U.S. EPA rule, a direct incorporation of rule would not support a rigorous California reporting program. As such, ARB staff rejected this alternative.

E. Summary of Proposed Board Action and Alternatives to: Asset-Controlling Supplier requirements – Section 95111

Staff is proposing to modify the requirements for the asset-controlling supplier application and reporting process. The amendments clarify that asset-controlling suppliers must report and verify annually, submit all necessary information to calculate their system emission factor, and in the case of an adverse verification statement, lose their status as an asset-controlling supplier, which includes their ARB-calculated system emission factor. In addition, the proposed language would explicitly indicate the timing and use of data for developing the specified source and asset-controlling supplier system emission factor. These changes ensure consistent treatment of all qualified entities wishing to apply for asset-controlling supplier designation and ensure that electric power entities have advanced knowledge of the reporting and verification status of the asset-controlling suppliers and their emission factors for reporting power transactions.

No Action Alternative.
In the current reporting regulation, the asset-controlling supplier application process is ambiguous and incomplete in addressing requirements to maintain an asset-controlling supplier designation. The requirements have at times been mistakenly interpreted to limit the application process to only one entity - the Bonneville Power Administration. In addition, the current requirements do not state the data year and timing for developing the asset-controlling supplier system emission factor. Without the proposed change, electric power entities may not find out about a change in an asset-controlling supplier's status or emission factor until after power contracts have been made, resulting in substantial cost impacts as a consequence of the asset-controlling supplier changes. For these reasons, ARB staff chose to reject this alternative.

Harmonization with U.S. EPA Alternative.
The U.S. EPA GHG reporting rule does not address electricity power imports nor provide for any designation of asset-controlling supplier; therefore the analysis for this alternative is identical to the "No Action" alternative addressed above.

F. Summary of Proposed Board Action and Alternatives to: Product Data Requirements – Sections 95103(k), 95103(l), and 95131(b)

Staff has proposed changes that specify that reporting accuracy requirements apply only to covered product data. Covered product data is product data used in the allocation of allowances under the cap-and-trade regulation, and is described in the newly added "covered product data" definition. This amended requirement would replace the previous requirement that all product data, including any non-covered product data, had to meet the material misstatement requirements as part of third party verification. The proposed revisions also change the requirements for the material misstatement assessment for covered product data to be based on "total" product data rather than the current requirement of an assessment on each single product data. These revisions will provide a cost savings to reporters of product data.

No Action Alternative.
Without the proposed changes, reporters would incur increased costs for maintaining meter and data accuracy requirements that were intended only for products that are be covered under the cap-and-trade program. In addition, reporters could incur greater verification costs as well. For this reason, ARB staff chose to reject this alternative.

Harmonization with U.S. EPA Alternative.
The U.S. EPA GHG reporting rule does not address the annual reporting of product for any of the product data listed in the reporting regulation. Therefore the analysis for this alternative is identical to the "No Action" alternative addressed above.

G. Summary of Proposed Board Action and Alternatives to: Verification Requirements – Section 95130

Staff is proposing to remove language that places verification requirements on facilities that emit below 25,000 $MTCO_2e$. Section 95130 of the reporting regulation currently indicates that reporting entities subject to reporting under section 95101 which are not eligible for abbreviated reporting must obtain third-party verification services. This means facilities subject to the no emission threshold reporting requirements of section 95101 must have their emissions data reports verified even if their emissions are below 25,000 $MTCO_2e$. It was not the intent of ARB staff to require facilities to obtain verification services if their emissions are below 25,000 $MTCO_2e$. The proposed change removes this language and clarifies that only facilities subject to section 95103(f) (emissions greater than or equal to 25,000 $MTCO_2e$) are subject to the verification requirements. This revision will provide a substantial cost savings to reporting entities in these sector categories.

No Action Alternative.
If this change was not made, some facilities with emissions below 25,000 and even some below 10,000 $MTCO_2e$ would be required to have their report verified by a third-party verifier. This requirement for small facilities would not be consistent with the intent of the verification requirements and would result in added costs for the affected facilities. For this reason, ARB staff chose to reject this alternative.

Harmonization with U.S. EPA Alternative.
The U.S. EPA GHG reporting rule does not address third party verification requirements; therefore the analysis for this alternative is identical to the "No Action" alternative addressed above.

H. Alternatives to Proposed Definition Amendments

In proposing the revisions to the reporting regulation described in this report, modifications, including additions, deletions, and revisions to existing defined terms, were necessary to ensure consistent and clear interpretation of terms used in the reporting, cap-and-trade, and fee regulations.

No Action Alternative: No Modifications to the Definitional Section of the Reporting Regulation.
Currently, the terms of the existing reporting regulation are included in the extant provisions of the regulation. If ARB did not adopt the revisions to the definitions as proposed in this rulemaking, the existing definitions would not allow for an accurate understanding or interpretation of the revised substantive and procedural provisions described herein. As such, ARB staff has rejected the "no action" alternative in order to ensure correct interpretation of regulatory terms, including those now proposed for explicit listing within the reporting regulation that were formerly incorporated by reference from the U.S. EPA reporting rule.

No Action Alternative: No Modifications to Definition Section of Fee Regulation.
The fee regulation contains terms which are generally consistent with those in the reporting regulation. ARB staff has strived to maintain consistent definitions for similar terms across its regulatory programs. If amendments to the definition section of the fee regulation are not made in conformance with the proposed revisions to the reporting regulation, entities subject to both regulations, as well as ARB, will not be able to consistently interpret identical terminology. As such, ARB staff has rejected this alternative in favor of proposing conforming amendments to the definition section of the fee regulation.

No Action Alternative: No Modifications to Definition Section of Cap-and-Trade Regulation.
The cap-and-trade regulation contains terms which are generally consistent with those in the reporting regulation. ARB staff has strived to maintain consistent definitions for similar terms across its regulatory programs. If amendments to the definition section of the cap-and-trade regulation are not made in conformance with the proposed revisions to the reporting regulation, entities subject to both regulations, as well as ARB, will not be able to consistently interpret identical terminology. As such, ARB staff has rejected this alternative in favor of proposing conforming amendments to the definition section of the cap-and-trade regulation.

IV. ENVIRONMENTAL IMPACTS OF THE REGULATION

A. Introduction

This chapter provides an environmental analysis for the proposed regulatory amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, the AB 32 Cost of Implementation Fee Regulation, and the Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms. Based on ARB's review, staff has determined that implementation of the proposed amendments would not result in any significant or potentially significant adverse impacts on the environment. This analysis provides the basis for reaching this conclusion. This section of the staff report also discusses the environmental benefits resulting from implementation of the proposed regulatory amendments.

B. Environmental Review Process

ARB is the lead agency for the proposed regulatory amendments and has prepared this environmental analysis pursuant to its regulatory program certified by the Secretary of the Natural Resources Agency (14 CCR 15251(d); 17 CCR 60005-60007). In accordance with Public Resources Code section 21080.5 of the California Environmental Quality Act (CEQA), public agencies with certified regulatory programs are exempt from the requirements for preparing environmental impact reports, negative declarations, and initial studies (14 CCR 15250). As required by ARB's certified regulatory program and the policy and substantive requirements of CEQA, ARB has prepared an assessment of the potential for significant adverse and beneficial environmental impacts associated with the proposed regulation and a succinct analysis of those impacts (17 CCR 60005(b)). This environmental analysis is included in the Staff Report: Initial Statement of Reasons (ISOR) prepared for the rulemaking (17 CCR 60005). The resource areas from the CEQA Guidelines Environmental Checklist were used as a framework for assessing the potential for significant impacts (17 CCR 60005(b)).

If comments received during the public review period raise significant environmental issues, staff will summarize and respond to the comments in writing. The written responses will be included in the Final Statement of Reasons (FSOR) for the regulation. Prior to taking final action on any proposed action for which significant environmental issues have been raised, the decision maker shall approve the written responses to these issues (17 CCR 60007(a)). If the regulation is adopted, a Notice of Decision will be posted on ARB's website and filed with the Secretary of the Natural Resources Agency for public inspection (17 CCR 60007(b)).

C. Prior Environmental Analyses

The Regulation for the Mandatory Reporting of Greenhouse Gas Emissions was originally developed pursuant to the California Global Warming Solutions Act of 2006 (AB 32), and became effective on January 1, 2009 (ARB MRR 2007). In 2010, ARB proposed additional revisions in order to support a California greenhouse gas (GHG) cap-and-trade program and to harmonize with the U.S. Environmental Protection Agency (U.S. EPA) federal mandatory GHG reporting requirements contained in Title 40, Code of Federal Regulations, Part 98. The 2010 revisions became effective on January 1, 2012 (ARB MRR 2010). The environmental analyses in the prior Staff Reports for the initial regulation and its 2010 revisions concluded that the regulation would not result in any significant environmental impacts.

The AB 32 Cost of Implementation Fee Regulation became effective on July 17, 2010 (COI 2010) Revisions to the Fee Regulation were approved by the Board in October 2011, and are scheduled to be submitted to the Office of Administrative Law by August 2012 (COI 2012) The environmental analyses in the initial staff report and subsequent revisions concluded that the regulation would not result in any significant environmental impacts (COI 2012 SR).

The California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms became effective on January 1, 2012 (C&T 2011). The environmental analysis in the initial staff report concluded that the covered entities' compliance with California's cap-and-trade regulation would result in beneficial impacts to air quality through reductions in emissions, including GHGs, criteria pollutants, and toxics, in addition to beneficial impacts to energy demand. It further concluded that the regulations would result in less-than-significant impacts or no impacts to aesthetics, agricultural and forest resources, hazards, land use, noise, employment, population and housing, public services, recreation, transportation and traffic, and utilities/service systems. It concluded there could be potentially significant adverse impacts to biological resources, cultural resources, geology/soils and minerals, and hydrology/water quality largely due to construction activities for facility-specific projects. Although the potential for adverse localized air quality impacts were found to be unlikely, ARB conservatively considered them potentially significant. The environmental analysis concluded that implementation of offset projects under California's protocols would also result in beneficial impacts to GHG emissions and no adverse impacts, or less-than-significant impacts, in all resource areas except for the following: California's Livestock Protocol has the potential for significant adverse impacts to odors, cultural resources, noise, and transportation/traffic; the Urban Forestry Protocol has the potential for significant adverse impacts to cultural resources; the Forest Protocol has the potential for significant adverse impacts to biological resources and land use.

D. Proposed Amendments

1. Description

The proposed regulatory amendments are described in detail in Chapters II and VII of this Staff Report. These changes clarify and amend existing requirements and definitions in the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions and provide conforming definitional changes to the AB 32 Cost of

Implementation Fee Regulation and the Regulation for the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms.

2. Methods of Compliance

In order to comply with the proposed amendments, the regulated community would collect and submit the required data in the required timeframe, as required by the regulations.

E. Environmental Impacts

Based on ARB's review of the proposed regulatory amendments, staff concludes that the amendments would not result in any significant or potentially significant adverse impacts on the environment because compliance with the proposed amendments would not result in any physical change to the existing environment. The amendments consist of administrative and procedural changes that affect only program administration and contents of databases, and do not involve or result in any new development, modifications to buildings, or new land use designations. Further, compliance with the proposed amendments would not involve any activity that would involve or affect aesthetics, air quality, agricultural and forestry resources, biological resources, cultural resources, geology and soils, greenhouse gases, hazardous material, hydrology and water quality, land use planning, mineral resources, noise, population and housing, public services, recreation, or traffic and transportation because they would not require any action that could affect these resources.

No discussion of alternatives or mitigation measures is necessary because no significant or potentially significant adverse environmental impacts were identified.

V. ENVIRONMENTAL JUSTICE

State law defines environmental justice as the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies (Senate Bill 115, Solis; Stats 1999, Ch. 690; Government Code § 65040.12(c)). The Board approved Environmental Justice Policies and Actions on December 13, 2001, to establish a framework for incorporating environmental justice into the ARB's programs consistent with the directives of State law. The policies subsequently developed apply to all communities in California, but they recognize that environmental justice issues have been raised more in the context of low income and minority communities, which sometimes experience higher exposures to some pollutants as a result of their proximity to multiple sources of air pollutants.

Actions of the ARB, local air districts, and federal air pollution control programs have made substantial progress towards improving the air quality in California. However, some communities continue to experience higher exposures than others because of the cumulative impacts of air pollution from multiple sources.

Adoption and implementation of the proposed amendments to the reporting regulation, and the conforming amendments to the definition sections of the fee regulation and the cap-and-trade regulation, will have no negative environmental impacts on environmental justice communities. Facilities throughout the state will be required to report their GHG emissions, with the focus on those facilities producing the highest levels of emissions. The amended regulations continues to include mandatory reporting for over 90 percent of the stationary source GHG emissions in California, including specified combustion, process, and fugitive emissions. Emissions information from these reports will be made available to the public.

VI. ECONOMIC IMPACTS

The economic impacts analysis shown in this staff report was conducted to meet current legal requirements under the Administrative Procedure Act (APA). Section 11346.3 of the Government Code requires that, in proposing to adopt or amend any administrative regulation, State agencies shall assess the potential for adverse economic impact on California business enterprises and individuals. The assessment shall include a consideration of the impact of the proposed or amended regulation on the ability of California businesses to compete with businesses in other states, the impact on California jobs, and the impact on California business expansion, elimination, or creation.

In this chapter, ARB staff provide the estimated costs to businesses and public agencies to comply with staff's proposed amendments to the mandatory California greenhouse gas (GHG) reporting requirements (the reporting regulation) and the conforming amendments to the definition sections of the AB 32 Cost of Implementation Fee Regulation (the fee regulation) and California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation (the cap-and-trade regulation). The amendments to the reporting regulation will affect approximately 94 reporting entities in the state, including 83 industrial facilities, 2 fuel suppliers, and 9 electricity generating facilities operated by local government. Given that various facilities are under common ownership, this equates to approximately 43 private businesses and 9 local government entities. The cost estimates are based on approximations of the amount of time required to comply with the amended provisions, associated labor wage rates, costs of any fuel sampling and analysis, and verification costs. The above approximations provide a general picture of the economic impacts that typical businesses subject to the proposed amendments might encounter. ARB staff recognizes individual companies may experience different impacts than those projected here, depending on various factors such as complexity of operation, types of emission units on-site, and existing compliance practices. Some facilities may experience an incremental cost increase, while some may experience an incremental cost saving as a result of the proposed amendments.

Overall, most affected businesses that may incur a cost are among the larger businesses in California. ARB staff does not expect these businesses to be affected adversely by the costs of the proposed amendments. Certain facility operators with emissions less than 25,000 $MTCO_2e$ will see an incremental saving. As a result, staff does not expect a noticeable change in employment, business creation, expansion, or elimination, or business competitiveness in California.

In performing this analysis, and given that the conforming amendments to the definition sections of the fee regulation and the cap-and-trade regulation do not modify the substantive or procedural requirements of reporting entities subject to those two regulations, staff does not expect any economic impacts to any private or public entity resulting from the conforming definitional amendments to those two regulations. As such, this chapter focuses primarily on an analysis of the potential economic impacts which may result from the amendments to the reporting regulation.

A. Summary of Costs and Economic Impacts

There are three primary costs associated with complying with the proposed amendments to the reporting regulation:

1) Emission reporting compliance costs, including costs incurred for monitoring, sampling, recordkeeping activities and the preparation of an annual emissions data report;
2) Costs for third-party verification of submitted GHG emissions data, when required; and
3) Costs to the State to administer the reporting program, including modifying the existing web-based reporting tool and data system to incorporate the proposed amendments.

In developing the amendments to the GHG reporting regulation, staff has attempted to minimize costs, while complying with the specific reporting requirements of AB 32 and collecting cap-and-trade quality data. The amended regulation will have noticeable cost impacts on only a subset of all the businesses currently subject to the extant California GHG reporting regulation. Other businesses that are already subject to the regulation will not experience a noticeable change in cost of compliance. In addition, certain facilities that are subject to the federal and State reporting programs regardless of the emission level (i.e. facilities with emission source categories listed in 40 CFR Part 98 Table A-3) that have emissions less than 25,000 MT of CO_2e will be exempted from third-party verification requirement, resulting in a cost saving. These include several electricity generating facilities operated by local government entities.

For all reporting entities state-wide, ARB staff estimates that the amended GHG reporting requirements will lead to a net saving of $158,000 per year for all affected entities, including businesses, local, and state government combined. The initial costs for training and planning incurred during the first year only are anticipated to be $50,000 statewide. These equate to a total net saving of $1.2 million for all affected entities state-wide over the course of 10 years, which can be further broken down to a saving of $871,000 over 10 years for private businesses, a saving of $356,600 for local government entities, and no cost impacts for state government entities. ARB staff anticipates costs to diminish over time as facilities incorporate GHG reporting into their normal business practices.

The amendments are expected to result in an annual cost saving of approximately $4,900 ($2,500-$7,000) per year for nine local government entities operating electricity generating facilities that are subject to the federal Acid Rain Program (40 CFR Part 75) (U.S. EPA Part 75 2009). The proposed rule amendments are not expected to affect any state government entities. The ranges of the estimated costs are wide because of the substantial variability in potential reporting and verification costs among facilities subject to the regulation.

Summaries of state-wide incremental costs are presented in Tables VI-1a and VI-1b.

Table VI-1a. Summary of State-Wide Incremental Costs for Private Businesses

Industry Sector	No. of Companies	No. of Reporting Entities[3]	Cost Incurring Sector		Cost Saving Sector	
			10-Year Cost[1] ($1000)	% of the Total Cost	10-Year Cost[1,2] ($1000)	% of the Total Saving
Electricity Generating Facility (Privately Owned)	8	26			(1,030.0)	83.1%
Cement Production	1	1			(70.0)	5.6%
Glass Production	3	3	21.6	5.85%		
Iron and Steel Production	1	1	11.65	3.15%		
Nitric Acid Production	1	1			(70.0)	5.6%
Oil & Gas Production	25	49	259.0	70.20%		
Petroleum Refineries	1	1			(70.0)	5.6%
Pulp and Paper Manufacturing	1	1	11.65	3.15%		
Fuel Suppliers-CNG/LNG Importers	2	2	65.1	17.65%		
SUM	**43**	**85**	**369**	**100%**	**(1,240)**	**100%**

1. All cost numbers are in 2011 dollars. Future costs are discounted at 5%.
2. Numbers in parenthesis denote a cost saving.
3. As defined in the GHG reporting regulation, a "reporting entity" is a facility, a supplier of fuel or CO_2, or an electric power entity.

Table VI-1b. Summary of State-Wide Incremental Saving for Local Government Entities (2011 $1,000)

	No. of Local Government Entities	No. of Facilities	Annual Cost ($1000)[1]	10-Year Cost ($1000)[1]
Electricity generating facilities operated by local government	9	9	(44)	(356.6)

1. Numbers in parenthesis denote a cost saving.

The proposed amendments will not require additional ARB funding. The amendments will be implemented using existing ARB staffing. Any ARB fiscal expenses needed for implementing the proposed amendments are already accounted for in the current operational budget that was approved as a part of the previous rule amendments.

Most businesses affected by the proposed amendments are the larger businesses in California, typically with millions of dollars in annual revenue. The cost of this amendment is not expected to have a significant material impact on these businesses. As a result, ARB staff does not expect a noticeable change in employment, business creation, elimination or expansion, or business competitiveness in California due the reporting requirements. ARB staff also expects no job or business losses due to the reporting regulation since most of the job creation associated with GHG reporting was gained following implementation of the original rule in 2007. Although it is not quantified, some technical consultants who will assist facilities in meeting the amended regulatory requirements may see a business expansion as the result of the proposed rule amendments.

Although the economic impacts of these amendments are not expected to have a direct impact on the health and welfare of California residents, worker safety, and the state's environment, the anticipated benefits of the amendments described in Chapter II may have indirect benefits on the health and welfare of California residents, on worker safety, and on the state's environment.

All the cost estimates provided in this chapter are given in 2011 dollars. The information, assumptions and methodologies used to determine compliance costs are summarized in Section C of this chapter.

B. Legal Requirements for Fiscal Analysis

Section 11346.3 of the Government Code requires that, in proposing to adopt or amend any administrative regulation, State agencies must assess the potential for adverse economic impacts on California business enterprises and individuals, including the ability of California businesses to compete with businesses in other states. The assessment must also include the potential impact of the regulation on California jobs, business expansion, elimination or creation, and the ability of California business to compete with businesses in other states.

Also, State agencies are required to estimate the costs or savings to any State or local agency and school district in accordance with instructions adopted by the Department of Finance. The estimate shall include any non-discretionary cost or savings to local agencies, and the cost or savings in federal funding to the State.

Health and Safety Code section 57005 requires ARB to perform an economic impact analysis of submitted alternatives to the proposed regulation before adopting any major regulation. A major regulation is defined as a regulation that will have a potential cost to California business enterprises in an amount exceeding ten million dollars in any single year. ARB staff has determined that the amendments to the proposed regulations are not a major regulation as defined above.

The following is a description of the methodology used to estimate costs, as well as ARB staff's analysis of the economic impact on California businesses and State and local agencies.

C. Analysis of Estimated Costs for Compliance

As a part of developing the regulatory amendments, ARB staff estimated the costs of compliance for facilities subject to the amendments. Briefly, the methodology for estimating costs for facilities and entities included:

- Establishing the baseline for the cost estimation, which is the cost of compliance to meet the requirements of the extant regulations;
- Categorizing affected reporting entities, which include those currently subject to reporting and those that may be potentially subject to reporting as a new reporter

under the proposed amendments;

- Identifying the new tasks that each facility type will need to perform to comply with the amended regulation, as well as the existing tasks that each facility type will no longer need to perform;
- Evaluating the incremental costs associated with the changes in tasks that are expected to be performed by the reporting entities in monitoring and sampling fuel, preparing emissions reports, creating or updating GHG monitoring plans, developing GHG emission estimates, and providing staff to prepare and submit the emissions reports. The labor costs are calculated by multiplying the estimated time requirements for performing each task by a range of wage rates from the U.S. Bureau of Labor Statistics (BLS 2011);
- Estimating the incremental costs for reporting facilities to contract with third-party verifiers to confirm that the facilities performed their emission estimates in compliance with the GHG reporting regulation;
- Applying the appropriate costs to each facility type to develop overall cost ranges for program implementation;
- Determining whether any affected facilities are operated by local or state government entities; and
- Analyzing costs to small businesses.

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

1. Scope of Cost Estimation

Baseline and Incremental Cost

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

- baseline compliance costs for GHG reporting under extant regulations, and
- additional compliance cost or saving under the proposed amendments.

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

Amended Rule Provisions with Noticeable Change in Costs

Many of the amended rule provisions provide clarifications to the rule requirements and do not lead to a noticeable change in cost. As mentioned previously, this is the case for the proposed conforming amendments to the definition sections of the fee regulation and the cap-and-trade regulation, which are not expected to have any economic impact on the entities covered by those regulations. Staff identified four proposed rule provisions in the reporting regulation that may lead to a noticeable change in costs.

ARB staff has estimated the economic impacts for each of these provisions in this analysis:

- Inclusion of process emission reporting for abbreviated reporters
- Exempting facilities listed in section 95101(a)(1)(A) with less than 25,000 $MTCO_2e$ of emissions from third-party verification requirements
- Inclusion of reporting imports of compressed and liquefied natural gas
- Additional monitoring and reporting requirements for oil and gas production entities

Cost Categorization of Affected Facilities

To estimate incremental costs incurred by reporting entities to comply with the proposed amendments, ARB staff categorized the affected entities by how they are affected by the combinations of amended rule provisions. To the extent possible, staff categorized the reporting entities into facility types that will be affected by the amendments in different ways, as some existing tasks are no longer required and new compliance tasks become effective under the amended rule.

Different types of facilities within the same industry sector will see different incremental impacts from the proposed rule amendments. In some cases, one industry sector can often be categorized into several facility types, with each expecting to see different incremental impacts. For example, the oil and gas sector is further categorized into 10 facility types by their industry segments and size: offshore production; onshore production- small, medium, large, very large; natural gas processing; natural gas transportation/compression; natural gas underground storage; natural gas distribution; existing abbreviated reporter; and new abbreviated reporter. In contrast, among all the facilities in the petroleum refineries sector that are subject to the GHG reporting regulation, only one facility may be potentially affected by the proposed amendments.

In total, ARB staff categorized the affected facilities into 21 facility types. The facility categorizations are listed in Table VI-2. For each facility category, ARB staff reviewed any changes in compliance tasks before and after the effective date of the proposed amendments and estimated the incremental costs of compliance for these tasks. The cost to perform a new task represents an incremental cost increase, while the cost to perform a current task that is no longer required under the amended rule represents an incremental cost saving (or a negative cost number). The following subsections describe the methodology that staff employed for the cost estimation.

Table VI-2. Facility/Fuel Supplier Categorization

Facility Type / Fuel Supplier Type	No. of Affected Reporting Entities[1]
Electricity Generating Facility, Part-75, <25K $MTCO_2e$, Private Entities	26
Electricity Generating Facility, Part-75, <25K $MTCO_2e$, Public Agencies	9
Cement Production, <25K $MTCO_2e$, existing reporter	1
Glass Production, <25K $MTCO_2e$, existing reporter	2
Glass Production, <25K $MTCO_2e$, new reporter	1
Iron and Steel Production, <25K $MTCO_2e$, new reporter	1
Nitric Acid Production, <25K $MTCO_2e$, existing reporter	1
Oil & Gas: Onshore production- small	10
Oil & Gas: Onshore production- medium	11
Oil & Gas: Onshore production- large	3
Oil & Gas: Onshore production- very large	2
Oil & Gas: Natural gas processing	4
Oil & Gas: Natural gas transportation/compression	9
Oil & Gas: Natural gas underground storage	2
Oil & Gas: Natural gas distribution	3
Oil & Gas: <25K $MTCO_2e$, existing reporter	6[2]
Oil & Gas: <25K $MTCO_2e$, new reporter	5
Petroleum Refineries, <25K $MTCO_2e$	1
Pulp and Paper Manufacturing, <25K $MTCO_2e$, new reporter	1
Importer of CNG/LNG- existing reporter	1
Importer of CNG/LNG- new reporter	1
TOTAL AFFECTED REPORTERS	**94**[2]
Private Industry	**85**[2]
Local Government	**9**
State Government	**0**

[1] As defined in the GHG reporting regulation, a "reporting entity" is a facility, a supplier of fuel or CO_2, or an electric power entity.
[2] The 6 facilities in the "Oil & Gas: <25K $MTCO_2e$, existing reporter" category are already accounted for among the other eight categories listed above it. However, a separate category must be created for it for a separate set of cost estimation due to the anticipated cost saving associated with the exemption from third-party verification requirements. Therefore, the 6 facilities are shown as duplicates in this table and are not added to the total facility count.

2. Costs of Performing Compliance Tasks

Staff utilized a method similar to an expert elicitation process to estimate the cost components, including labor costs (associated with monitoring, sampling, recording, training, and planning), fuel analysis cost, equipment cost, and verification cost, based on staff's experience in providing support to reporting entities and verification bodies. The method for estimating each cost component is described below.

Number of Affected Facilities and Companies

For industrial facilities, cost estimation was performed on a facility basis, not on a company basis. This is because the rule applicability of the GHG reporting regulation is determined on a facility basis. For this reason, the number of companies impacted by the regulation is smaller than the number of facilities impacted because many impacted companies operate multiple facilities. On the other hand, the reporting boundary and regulation applicability for fuel suppliers and electric utilities is determined on a company basis in the reporting regulation. Therefore, the cost analysis for these types of facilities was done on a company basis.

ARB staff leveraged the inventory data collected under the existing GHG reporting program (2008-2011 data years) (ARB GHG Summary 2008-2011) to determine the number of facilities affected by each amended rule provision. Using the facility types in Table VI-2, their respective characteristics, and other knowledge about the facilities that staff acquired through assisting reporters and verifiers, staff analyzed the inventory data and counted the number of potentially affected facilities. The identified affected facilities are grouped by their parent company to determine the number of affected businesses in each sector. The numbers of facilities were multiplied by the estimated incremental costs per facility to obtain the sector-wide and program-wide cost impacts. The average cost per company was calculated by dividing the total sector-wide cost by the estimated number of companies in the sector.

Labor Costs

Estimation of Labor Hours. Since the inception of the California GHG reporting program in 2008, ARB staff has been working closely with reporting entities in providing technical support for emission calculations, providing training on the rule requirements and the use of the reporting tool, assisting reporters in preparing and submitting electronic GHG reports, and noting informal feedback from reporters on the time requirements of GHG reporting. ARB staff also works closely with the accredited verifiers to ensure the quality of GHG reports by observing the on-site practices of reporting entities (observations took place during verification site visits), and collecting informal feedback provided by verifiers and reporters regarding the expenses of GHG reporting and verification. The knowledge gained by ARB staff's direct involvement with reporters and verifiers over the last three years has given staff an understanding of the cost and workload of implementing this regulation. With this knowledge, staff has estimated the range of costs and hours spent on the following compliance tasks:

- Becoming familiar with rule requirements and the use of the reporting tool, preparing and implementing GHG monitoring plan, and training facility staff in performing compliance tasks;
- Collecting and analyzing fuel samples, keeping records of fuel analytical data, and calculating emissions at various periodic sampling frequencies;

- Monitoring proper operation of fuel or feedstock measurement equipment and recording consumption data;
- For suppliers of fuels, gathering data required for GHG reporting from their existing database system;
- For oil and gas facilities, complying with the additional monitoring, sampling, testing, and reporting requirements;
- For each applicable sector, performing additional process emissions calculations called for by the respective sections of the proposed amended regulation;
- Entering data, performing quality assurance (QA) checks, and certifying and submitting GHG report in the reporting tool;
- Coordinating, preparing records for, and hosting verification site visits; and
- Following-up on verification and revising the GHG emissions data report as needed.

ARB staff estimated the incremental time requirement of different compliance tasks that are expected for the 21 facility types. Most facility types are expected to see only 1 to 4 incremental tasks listed above as the result of the amendments, although they may already be performing most of these tasks under the existing regulations.

Cost of Reporting. For the purpose of satisfying the requirements in Section 11346.3 of the Government Code, ARB staff has assessed the labor costs related to reporting emission data ("cost of reporting") as consisting of the costs associated with recordkeeping, submitting data through the web-based reporting tool system, and certifying and submitting the report, which is a subset of the total reporting costs. Costs for training and planning, fuel sampling and testing, emission monitoring, emission calculation, and third-party verification are not included in the "cost of reporting." "Cost of reporting" and other labor costs are all estimated using the methodology described in this subsection.

Staff identified the facility types that can be expected to see a noticeable incremental "cost of reporting" and estimated the labor costs associated with the three "cost of reporting" compliance tasks. The average "cost of reporting" is calculated as the sum of the weighted-averages of the costs for each of the three compliance tasks, weighted by the number of facilities in each facility type. The facility types are mapped into the categories shown below, where the incremental costs of reporting are assumed to be similar among the facility types in each category shown below. (See Table VI-2 for facility types characterization.) In this case, cost per facility is the same as cost per company because the affected companies operate only one facility in the affected facility types. There is a one-to-one correspondence between "facility" and "company."

Existing reporters with fuel combustion emissions in the 10,000-25,000 $MTCO_2e$ range, which may be affected by the proposed changes:

- Cement production, <25K $MTCO_2e$, existing reporter (1 reporter)
- Glass production, <25K $MTCO_2e$, existing reporter (2 reporters)
- Nitric acid production, <25K $MTCO_2e$, existing reporter (1 reporter)
- Oil & gas production, <25K $MTCO_2e$, existing reporter (6 reporters)

- Petroleum refineries, <25K $MTCO_2e$ (1 reporter)

Potential new abbreviated reporters, which may be affected by the proposed changes:

- Glass production, <25K $MTCO_2e$, new reporter (potentially 1 reporter)
- Iron & steel production, <25K $MTCO_2e$, new reporter (potentially 1 reporter)
- Oil & gas production, <25K $MTCO_2e$, new reporter (potentially 5 reporters)
- Pulp & paper manufacturing, <25K $MTCO_2e$, new reporter (potentially 1 reporter)

Importers of CNG/LNG, which may be affected by the proposed changes:

- Importer of CNG/LNG, existing reporter (potentially 1 reporter)
- Importer of CNG/LNG, new reporter (potentially 1 reporter)

Facility Staff Time in Support of Verification. ARB staff estimated different levels of time required to better represent the efforts needed for a facility based on the complexity of verification-related tasks. For example, a moderately complex facility such as a nitric acid production facility is likely to spend more time preparing for and hosting a verification site visit than a simple facility such as an electricity generation plant with only one natural gas-fired engine. ARB staff developed time requirement estimates for a simple and moderately complex facility for preparing and hosting the verification site visit, and applied them to each facility type. The total labor costs for performing each compliance task were estimated by multiplying the estimated time requirement of the task by a range of wage rates (in $/hour) for the type of facility staff that typically performs the task.

Wage Rate by Staff Class. ARB staff assigned each individual task to a corresponding staff classification. Staff classifications include administrative staff, technical staff, managerial staff, and lawyers. The technical staff classification is further divided: 1) technical staff 1 may include junior engineers, scientists, senior operators, and senior technicians; and 2) technical staff 2 may include mid- to senior- level engineers or compliance specialists.

The U.S. Bureau of Labor Statistics (BLS) 2011 Occupational Employment and Wage Estimates data (BLS 2011) for the state of California are used to construct ranges of wage rates. The wage data for several similar occupations that are likely to perform the compliance tasks are combined together to form the 5 staff classifications in the analysis. For example, the technical staff 2 wage rate range is a composite of wage rates of chemical, civil, environmental, industrial, mechanical, and health and safety engineering occupations. The minimum 25th percentile, the maximum 75th percentile, and the average of the median wage rate values in the BLS data set are used as low, high, and mid estimates, respectively.

To account for the total labor costs incurred by the reporting entities, which may include employee benefits and overhead costs, staff applied the same adjustment factors that U.S. EPA used in estimating the economic impacts of the federal GHG reporting program (USEPA 2009a). These adjustment factors are a "benefit loading factor" of 0.5 and an "overhead loading factor" of 0.17. In other words, the ranges of wage rates extracted from BLS data are scaled up by a factor of 1.67 to obtain the final "loaded wage rate" numbers for the labor cost analysis. The resulting loaded wage rates for the 5 facility staff classes in 2011 dollars are summarized in Table VI-3.

Table VI-3. Wage Rates Used to Estimate Labor Costs

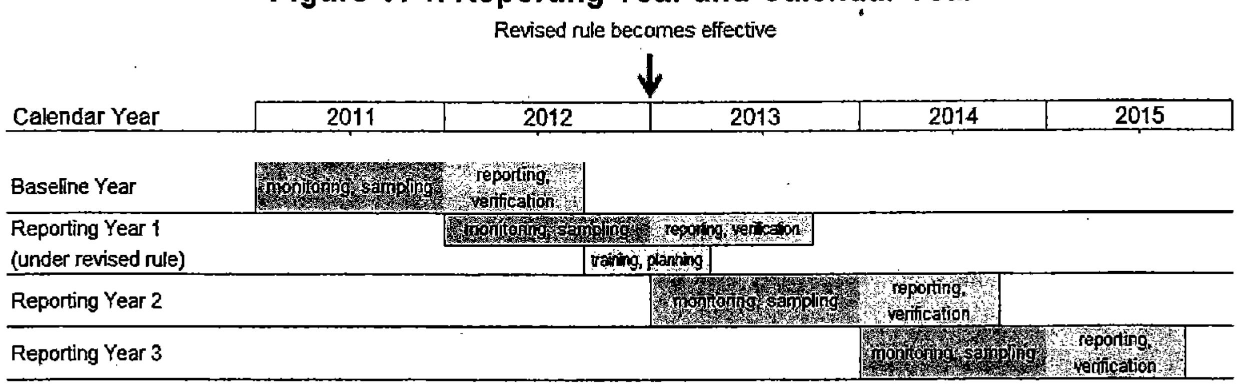
Facility Staff Class	Loaded Wage Rate (2011$/ hour)		
	Low	Mid	High
Administrative	21.31	24.03	28.44
Technical 1	34.89	49.07	62.09
Technical 2	52.39	71.27	79.99
Managerial	75.15	91.97	114.86
Lawyer	81.41	114.68	147.95

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

Annual Cost Summed by Reporting Cycle vs. by Calendar Year

To keep cost accounting on a yearly basis, ARB staff summed the costs by the yearly reporting cycle, which does not coincide with one calendar year. For example, the labor costs for recording fuel use and collecting/analyzing fuel samples are expended during calendar year 1. Labor costs for performing emission calculations, reporting and verification of the year 1 typically occur in calendar year 2. In addition, during calendar year 2, there are new costs for collecting data for the next reporting cycle. Therefore, each calendar year has both cost for the collection of data and the cost for reporting and verification, which makes up the reporting cycle. For purposes of this analysis, each reporting cycle takes into account the collection and reporting and verification costs. Figure VI-1 graphically illustrates the overlap of "reporting year" and "calendar year."

Figure VI-1. Reporting Year and Calendar Year



Equipment Costs

Staff does not anticipate that the affected facilities will need to purchase new equipment to comply with the amended rule requirements. They should already have the necessary equipment in place for GHG reporting due to the existing California reporting regulation, other federal or local requirements, or normal industry practices.

Cost of Third-Party Verification Service

In working closely with the accredited verifiers and collecting feedback informally provided by verifiers and reporters, ARB staff has compiled estimated ranges of verification service fees that reporting entities spent to comply with the existing verification requirements.

Using the ranges of verification service fees and the estimated time requirements for verifiers to perform specific verification-related tasks, staff estimated the likely ranges of verification service fees, which could either be an intensive verification or less-intensive verification. Most facilities will need to go through an intensive verification at least once every 3 years, and it is assumed that for the other 2 years, approximately half of the facilities will have no major issues to warrant an intensive verification and a less-intensive verification will suffice.[1] Staff estimated the ranges of verification service fees and the time requirements for facility staff to perform various verification-related tasks during both intensive and less-intensive verifications, and applied these costs to each facility type that is expected to see an incremental change to verification-related costs. The annual verification cost in the on-going years is a composite of the cost expected for a typical intensive verification year and a typical less-intensive verification year, where each is weighted equally at 50%.

New Reporters Subject to Process Emissions Reporting

The existing regulation requires facilities with total emissions of more than 25,000 $MTCO_2e$ (including combustion, process, vented, and fugitive emissions) to report process emissions, but does not require those that are less than 25,000 $MTCO_2e$ to report process emissions. The proposed amendment requires facilities in the sectors with specified process emissions, but that have less than 25,000 $MTCO_2e$ of total emissions, to begin reporting process emissions annually. The incremental costs per affected facility are estimated using the approach described in the previous subsections.

To determine the number of potentially affected facilities, staff reviewed an inventory of emission sources (ARB CEIDARS 2007) compiled by ARB staff using information requested and obtained from the local air quality management districts and air quality control districts. Although it can provide a general sense of the number of potentially affected entities, this inventory may not be a precise projection of which entities may be

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

affected. Each potentially affected entity must conduct a GHG emission inventory to determine their applicability to the amended regulation. ARB staff estimated that there may potentially be between 0 to 15 (middle value 8) additional industrial facilities newly subject to GHG reporting due to this proposed provision, and these new reporters may use the abbreviated reporting option since their emissions do not exceed the 25,000 $MTCO_2e$ threshold.

Oil and Gas Sector

The upstream oil and gas industry in California is comprised of the following five industry segments (as defined by U.S. EPA):

- Onshore oil and natural gas production – 25 reporters
- Natural gas processing facilities – 5 reporters
- Natural gas transmission/compression facilities – 9 reporters
- Natural gas underground storage facilities – 2 reporters, and
- Natural gas distribution systems – 3 reporters

Incremental costs for both equipment/analysis and personnel time were estimated for each of these industry segments for each of the eight GHG calculation methodologies where ARB reporting requirements were different for those of the U.S. EPA. The remaining ten GHG emission calculation methodologies contained in this section do not require additional expenditures or personnel time.

Estimates were done for the initial year of implementation when first time costs related to set-up and equipment purchases may be larger than those in succeeding years. The additional time requirements (in person hours) were summed and multiplied by labor wage rate (BLS 2011) and the number of affected California reporters to arrive at the overall first year and subsequent year personnel cost differential.

State and Local Government

GHG reporting as specified is mandatory for any facility or entity that meets the regulation's applicability requirements. Therefore, some public agencies are subject to reporting, such as certain county or city owned sewage treatment works or landfills, local municipal utility districts or electric retail providers, some State universities, and other State facilities that emit more than 10,000 metric tons of CO_2e from stationary combustion sources. The Department of Water Resources is also expected to have a reporting requirement related to imported power.

Staff has determined that the only amended rule provision that may affect public entities is the exemption of Part 75 facilities with less than 25,000 $MTCO_2e$ of emissions from third-party verification requirements. Staff reviewed the list of currently reporting entities and identified 9 electricity generating facilities operated by local government entities that belong to this category. No state agency is expected to see a noticeable incremental cost or saving from the proposed amendments. The nine electricity generating facilities operated by local agencies are listed in Table VI-4.

Table VI-4. List of Electricity Generating Facilities Operated by Local Government Entities That May Potentially be Exempt from Verification Requirements

Facility Name
City of Anaheim, Combustion Turbine Generator
Imperial Irrigation District (IID), Niland Gas Turbine Plant
Modesto Irrigation District - Ripon Generation Station
Northern California Power Agency - Lodi Combustion Turbine Project No. 2
Pasadena Water and Power, Broadway
Redding Electric Utility - Redding Power Generation
Riverside Public Utilities - Riverside Energy Resource Center
City of Colton, El Colton LLC
Kings River Conservation District - Malaga Peaking Plant

Like their counterparts in the private sectors, publicly owned electricity generating facilities that emit less than 25,000 MT of CO_2e are expected to see a cost saving from being exempt from verification requirements. Since the proposed exemption applies the same to affected facilities regardless of public or private ownership, the same cost applies to a local government-operated facility as to a generic facility in the "electricity generating facility, Part 75, <25K $MTCO_2e$" category (see Table VI-2). To estimate the total costs to the affected local government entities, staff multiplied the expected incremental cost per facility for this category by 9 facilities, where the cost per facility was calculated using the approach described in the previous subsections. The cost estimation results are presented in Section D.

Small Businesses

Using the estimation techniques described below, ARB staff conservatively estimated there may be approximately 3 small business entities that may be affected by the proposed amendments to the regulation. The estimated numbers of affected small businesses entities by sector are summarized in Table VI-5 below.

Small Business Description: A small business, which is defined by the California Government Code Section 11342.610 (CGC 2012) as:

(a) "Small business" means a business activity in agriculture, general construction, special trade construction, retail trade, wholesale trade, services, transportation and warehousing, manufacturing, generation and transmission of electric power, or a health care facility, unless excluded in subdivision (b), that is both of the following:

(1) Independently owned and operated.

(2) Not dominant in its field of operation.

(b) "Small business" does not include the following professional and business activities:

(1) A financial institution including a bank, a trust, a savings and loan association, a thrift institution, a consumer finance company, a commercial finance company, an industrial finance company, a credit union, a mortgage and investment banker, a securities broker-dealer, or an investment adviser.
(2) An insurance company, either stock or mutual.
(3) A mineral, oil, or gas broker.
(4) A subdivider or developer.
(5) A landscape architect, an architect, or a building designer.
(6) An entity organized as a nonprofit institution.
(7) An entertainment activity or production, including a motion picture, a stage performance, a television or radio station, or a production company.
(8) A utility, a water company, or a power transmission company generating and transmitting more than 4.5 million kilowatt hours annually.
(9) A petroleum producer, a natural gas producer, a refiner, or a pipeline.
(10) A manufacturing enterprise exceeding 250 employees.
(11) A health care facility exceeding 150 beds or one million five hundred thousand dollars ($1,500,000) in annual gross receipts.

(c) "Small business" does not include the following business activities:

(1) Agriculture, where the annual gross receipts exceed one million dollars ($1,000,000).
(2) General construction, where the annual gross receipts exceed nine million five hundred thousand dollars ($9,500,000).
(3) Special trade construction, where the annual gross receipts exceed five million dollars ($5,000,000).
(4) Retail trade, where the annual gross receipts exceed two million dollars ($2,000,000).
(5) Wholesale trade, where the annual gross receipts exceed nine million five hundred thousand dollars ($9,500,000).
(6) Services, where the annual gross receipts exceed two million dollars ($2,000,000).
(7) Transportation and warehousing, where the annual gross receipts exceed one million five hundred thousand dollars ($1,500,000).

Estimation Methods: The California Employment Development Department Labor Market Information Division publishes data on the number of establishments by size category classified by the North American Industry Classification System (NAICS) (CEDD 2009).[2] This dataset contains estimated numbers of establishments that fall into nine "employment size categories" (e.g. number of establishments with "0-4 employees," "50-99 employees," "1000+ employees," etc.) for NAICS sectors at the 2-digit or 3-digit level. The NAICS codes reported by the entities that are currently in the GHG reporting program are mapped to the 2-digit or 3-digit NAICS codes in the CEDD dataset. The size categories in CEDD data are then aggregated into two employment size categories: "less than 250 employees" and "greater than 250 employees." The proportion of establishments that have less than 250 employees is calculated for each sector.

The estimated numbers of small business entities are calculated by multiplying the proportion of "less than 250 employees" establishments by the projected number of affected entities in each sector. These numbers are expected to overestimate the actual number of affected small businesses due to the following reasons. First, given that a business can own multiple establishments (or "facilities" in the context of GHG reporting), the actual number of affected businesses should be smaller than the number of affected establishments. Secondly, given that entities with high emissions tend to have higher outputs, leading to higher revenues, higher employment, and driving higher fuel consumption, the entities that exceed the reporting thresholds (of 25,000 MT of CO_2e or 10,000 MT of CO_2e) are less likely to meet the criteria of qualified small business. ARB staff anticipates that in reality, the proportions of "less than 250 employees" establishments should distribute unevenly at the different emissions levels (i.e. the ">25,000 MT of CO_2e" group is less like to contain any small business entities than the "10,000 to 25,000 MT of CO_2e" group or the "<10,000 MTCO2e" group), which determine the applicability of the regulation. The actual number of affected small businesses should be smaller than the estimates obtained using this approach.

Oil and Gas Production, Petroleum Refineries, and Fuel Suppliers: Per Section 11342.610(b)(3) and (9), any affected entities in the oil and gas production, petroleum refineries, and fuel suppliers sectors do not qualify for small business status regardless of their revenue and employment size. Therefore, there are no small business entities in these sectors.

Electricity Generating Facilities: Per Section 11342.610(b)(8), any electricity generating facilities and electric utilities that generate or transmit more than 4,500 MWh of electricity annually do not qualify for small business status. Staff analyzed the inventory data collected through the existing GHG reporting program to identify any electricity

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

generating facilities that: (1) generate less than 4,500 MWh of electricity annually, (2) are subject to 40 CFR Part 75 and have less than 25,000 $MTCO_2e$ of emissions (and thus will be affected by the exemption from third-party verification requirement), (3) whose parent company's entire generation capacity in State does not exceed the 4,500 MWh threshold, and (4) that are not facilities operated by state and local government entities. ARB staff found no affected electric utilities or electricity generating facility operator meeting the criteria for small business status.

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

Glass Production and Pulp and Paper Manufacturing Facilities: For the glass production and pulp & paper manufacturing sectors, ARB staff estimated the likely proportions of small businesses in each affected sector using employment statistics published by California Employment Development Department (EDD). The threshold of 250 or less employees was used for the estimation. The approach of using state-wide proportion of <250 employees business in each industry sector should provide a conservative high estimation, as described above.

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

Industry Sector	No. of Small Business	Note
Electricity Generating Facility	0	Based on the inventory data collected through existing GHG reporting program, no affected electricity generating facilities meet the Section 11342.610(b)(8) criteria.
Cement Production	0	Per D&B Selectory search, no affected facility qualifies for small business status.
Glass Production	1	Using CEDD data as the basis for estimation, approximately 16% of the establishments in this sector have <250 employees. Staff estimates that there may be 1 facility potentially affected by the amendments and assumes 1 small business to be conservative.
Hydrogen Production	0	Per D&B Selectory search, no affected facility qualifies for small business status.
Iron and Steel Production	1	Per D&B Selectory search, no affected facility qualifies for small business status. Staff estimates that there may be 1 facility potentially affected by the amendments and assumes 1 small business to be conservative.
Lime Manufacturing	0	Per D&B Selectory search, no affected facility qualifies for small business status.
Nitric Acid Production	0	Per D&B Selectory search, no affected facility qualifies for small business status.
Oil & Gas Production	0	Not qualified for small business per California Government Code Section 11342.610(b)(3)&(9)
Petroleum Refineries	0	Not qualified for small business per California Government Code Section 11342.610(b)(3)&(9)
Pulp and Paper Manufacturing	1	Using CEDD data as the basis for estimation, approximately 14% of the establishments in this sector have <250 employees. Staff estimates that there may be 1 facility potentially affected by the amendments and assumes 1 small business to be conservative.
Fuel Suppliers-CNG/LNG Importers	0	Not qualified for small business per California Government Code Section 11342.610(b)(3)&(9)
TOTAL	3	

D. Economic Impacts of Proposed Regulation

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

1. Overview of State-Wide Costs by Sector

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

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

Table VI-6. Sector-Wide Incremental Cost Impacts

			Sector-Wide Incremental Costs ($1,000)[1]		
Sector	Number of Company	Number of Reporting Entities[2]	1st-Year Only	On-going Years	10-Yr Cost
Electricity Generating Facility (private business)	8	26	-	(127.32)	(1,030.0)
Cement Production	1	1	-	(8.66)	(70.0)
Glass Production	3	3	3.14	2.28	21.6
Iron and Steel Production	1	1	3.14	1.05	11.6
Nitric Acid Production	1	1	-	(8.66)	(70.0)
Oil & Gas Production	25	49	37.92	27.32	259.0
Petroleum Refineries	1	1	-	(8.66)	(70.0)
Pulp and Paper Manufacturing	1	1	3.14	1.05	11.6
Fuel Suppliers-CNG/LNG Importers	2	2	2.80	7.70	65.1
Private Industry Total	**43**	**85**	**50**	**(114)**	**(871)**
Electricity Generating Facility (local government entities)		9	0	(44)	(357)
Total for All Affected Reporters		**94**	**50**	**(158)**	**(1,228)**

[1] All costs are in thousands of 2011 dollars. Future costs are discounted at 5%. Numbers in parenthesis are negative, indicating a cost saving.
[2] As defined in the GHG reporting regulation, a "reporting entity" is a facility, a supplier of fuel or CO_2, or an electric power entity.

As shown in Table VI-6, the proposed rule amendment is expected to have a net state-wide cost saving of $158,000 annually ($114,000 for the private industry sectors and $44,000 for local government entities). Additional costs for training and planning during the first year only are approximately $50,000. Using a discount rate of 5% and a time horizon of 10 years, the total net state-wide saving is approximately $1.2 million over 10 years ($871,000 for the private industry sectors and $357,000 for local government entities). A 10-year time horizon is assumed for the analysis because ARB staff expects that the GHG reporting regulation may potentially be amended again between 2012 and 2022, due to potential new federal regulations or cap-and-trade program requirements.

The electricity generating, cement production, nitric acid production, and petroleum facilities with less than 25,000 $MTCO_2e$ of emissions can expect to see a net cost saving from the amended regulation due to the proposed exemption from verification requirements. The other sectors are expected to see a net incremental cost increase due to additional monitoring and reporting requirements in the proposed regulation. State-wide, most of the incremental costs are borne by the oil and gas production sector, accounting for 70% of the total costs among the cost-incurring sectors. The incremental costs to the other sectors make up the remaining 30% of the state-wide costs.

2. Impacts to California Businesses

The proposed GHG reporting regulation focuses on the largest stationary sources of GHG emissions and other sources that must be included for an effective cap-and-trade program. The specific incremental cost for a facility subject to GHG reporting can vary significantly depending on each facility's unique situation in terms of its sector designation, type and size of its fuel combustion equipment, facility complexity, emissions level, and its current monitoring and sampling practices as compared to its future requirements under this proposal.

For an individual reporting entity (which may either be an industrial facility or a fuel supplier, as defined in the GHG reporting regulation), the incremental cost per entity could range widely. Incremental costs for typical businesses (other than those in the oil and gas production sector) subject to the proposed amendments will generally be small for facilities that are already subject to current GHG reporting programs, because the bulk of the baseline costs will be incurred complying with the existing ARB reporting regulation and the U.S. EPA regulation. Some reporting entities are expected to see a net cost saving as the result of the proposed amendments. Electricity generating facilities, cement production facility, nitric acid production facility, and petroleum refineries emitting less than 25,000 MT of CO_2e will experience a cost saving because they will no longer be required to obtain third-party verification services.

With the proposed amendments, ARB staff anticipates additional costs during the initial year for certain facility types, as reporters become familiar with the new requirements, update or develop GHG monitoring plans, and develop expertise with the new reporting systems and methods. However, ARB staff anticipates industry costs to decline over time as the amended GHG reporting requirements become incorporated into standard facility practices.

Costs per reporting entity by facility type are presented in Table VI-7. Because facilities within the same sector can be further categorized into more detailed facility types depending on how they are affected by the amended regulation (see Section C.1—Costs Categorization of Affected Facilities for a discussion of the facility categorization), a wide range of values for cost per entity can be expected even within the same sector.

Table VI-7. Average Incremental Cost Impacts per Facility or per Fuel Supplier

	First-Year-Only Cost per Facility ($)[1,2]		On-Going Annual Cost per Facility ($)[1,2]	
Facility Type	Mid Estimate	Range	Mid Estimate	Range
Electricity Generating Facility, Part-75, <25K $MTCO_2e$, Private Entities	0	[0, 0]	(4,897)	[-2500, -7100]
Electricity Generating Facility, Part-75, <25K $MTCO_2e$, Public Agencies	0	[0, 0]	(4,897)	[-2500, -7100]
Cement Production, <25K $MTCO_2e$, existing reporter	0	[0, 0]	(8,656)	[-4900, -17600]
Glass Production, <25K $MTCO_2e$, existing reporter	0	[0, 0]	614	[300, 1000]
Glass Production, <25K $MTCO_2e$, new reporter	3,137	[1700, 5000]	1,051	[400, 2000]
Iron and Steel Production, <25K $MTCO_2e$, new reporter	3,137	[1700, 5000]	1,051	[400, 2000]
Nitric Acid Production, <25K $MTCO_2e$, existing reporter	0	[0, 0]	(8,656)	[-4900, -17600]
Oil & Gas: Onshore production- small	641	[500, 700]	499	[300, 600]
Oil & Gas: Onshore production- medium	641	[500, 700]	499	[300, 600]
Oil & Gas: Onshore production- large	641	[500, 700]	499	[300, 600]
Oil & Gas: Onshore production- very large	641	[500, 700]	499	[300, 600]
Oil & Gas: Natural gas processing	214	[100, 200]	71	[50, 200]
Oil & Gas: Natural gas transportation/compression	285	[200, 300]	285	[200, 400]
Oil & Gas: Natural gas underground storage	428	[300, 500]	428	[300, 600]
Oil & Gas: Natural gas distribution	428	[300, 500]	570	[400, 700]
Oil & Gas: Oil and Gas Production, <25K $MTCO_2e$, existing reporter	0	[0, 0]	614	[300, 1000]
Oil & Gas: Oil and Gas Production, <25K $MTCO_2e$, new reporter	3,137	[1700, 5000]	1,051	[400, 2000]
Petroleum Refineries, <25K $MTCO_2e$	0	[0, 0]	(8,656)	[-4900, -17600]
Pulp and Paper Manufacturing, <25K $MTCO_2e$, new reporter	3,137	[1700, 5000]	1,051	[400, 2000]
	First-Year Only Cost per Supplier ($)[1,2]		On-Going Year Cost per Supplier ($)[1,2]	
Supplier Type	Mid Estimate	Range	Mid Estimate	Range
Importer of CNG/LNG- existing reporter	0	[0, 0]	1,693	[900, 2300]
Importer of CNG/LNG- new reporter	2,803	[2100, 6100]	6,007	[3100, 8900]

[1] All costs are in 2011 dollars. Negative numbers indicate a cost saving.
[2] For industrial facilities, because the rule applicability of the GHG reporting regulation is determined on a facility basis, and the reporting program is also implemented using individual facilities as the reporting unit, all the building blocks of cost estimation are performed on a facility basis, not on a company basis. See Section VI.C.2, *Number of Affected Facilities and Companies* subsection and the description in the following page for an explanation of cost of company calculations.

As explained in Chapter VI.C.2, the boundary of "reporting entity" as defined by the regulation is the same as "company" or "business entity" for fuel suppliers and electric utilities, but not for industrial facilities. (Electric utilities operating power plants must submit a separate report for each of their power plants, in addition to the power entity report they must submit for their power transaction, imports, exports, and retail sales. A power plant is considered an industrial facility in this case.) Due to the broad coverage of the GHG reporting regulation, the diversity of facility types even within the same sector, and the complexity associated with many companies owning/operating multiple facilities in different facility type categories and in multiple sectors, it is very difficult to directly estimate the cost per company. Instead, the average cost per company is calculated by dividing the total net cost incurred by the private industry by the number of companies, which gives the weighted average of cost per company that is weighted by the number of companies in each industry sector.

Using this approach, the weighted-average cost per company per year in the on-going year is calculated to be -$2,648 (a net saving, which is calculated as -$113,884 total private industry cost divided by 43 companies). For a "typical business," excluding 3 potential small business entities, the average cost is -$2,919 per company per year (a net saving, which is calculated as -$113,884 total private industry cost, minus $760 weighted-average glass production facility cost that is weighted by the number of facility in two facility types in the glass production sector, minus $1,051 for one iron & steel production facility, minus $1,051 for one pulp & paper manufacturing facility, then divide the result of subtraction by 40 companies). Similarly, the weighted-average first-year-only cost per company is calculated to be $1,166 (a net cost, which is calculated as $50,134 total private industry first-year-only cost divided by 43 companies). For a "typical business," excluding 3 potential small business entities, the average cost is $1,070 per company per year ($50,134 total private industry first-year-only cost, minus $1,046 weighted-average glass production facility cost that is weighted by the number of facility in two facility types in the glass production sector, minus $3,137 for one iron & steel production facility, minus $3,137 for one pulp & paper manufacturing facility, then divide the result of subtraction by 40 companies).

The main sources of uncertainties in the economic impact analysis are from the ranges of wage rates in the U.S. Bureau of Labor Statistics data and the ranges of the estimated time requirement to perform compliance tasks. The high estimates shown in the cost table represent the scenario in which the affected entity uses staff whose salary is high in their respective staff classifications, and the amount of time that the high-salaried staff takes in doing the compliance tasks is also on the high end of the range of estimates. On the other hand, the low estimates represent the scenario in which the affected entity uses staff whose salary is on the low side of the wage rate range, and each staff takes little time to accomplish the compliance tasks. The high and low estimates are shown here for bounding purposes, and they are extremely unlikely in reality because private businesses tend to minimize cost by maximizing efficiency. When factoring in all uncertainties in either direction, the net costs are likely to be close to the middle estimates.

3. Impacts to Small Businesses

Using a combination of estimation techniques described in Section C of this chapter, staff conservatively estimated that approximately 3 small business entities may be affected by the proposed amendments. Other than their high-level industry sector designation, staff does not know exactly how these small business entities distribute among the different facility types in the affected sectors, which is the main factor for determining whether an individual entity may incur a net incremental cost or see a net incremental saving. Nevertheless, staff expects that if there are any small businesses affected by the amendments, they are more likely be in the 10,000 to 25,000 MT of CO_2e categories and are eligible for abbreviated reporting; therefore, they should incur relatively less total costs than their counterparts with emissions >25,000 MT of CO_2e.

The estimation results presented in Table VI-5 show that there may potentially be one affected small business in each of the glass production sector, the iron & steel production sector, and the pulp and paper manufacturing sector. ARB staff does not anticipate there are any affected small business entities in the remaining sectors.

Since the proposed amendments apply to affected facilities regardless of small business status, incremental costs should apply the same to a small business as to a generic facility in the respective facility type. Staff estimates that a glass production facility may incur an incremental on-going annual cost of $760 (which is the weighted-average glass production facility cost, weighted by the number of facilities in 2 facility types in the glass production sector) (lower and upper bound estimate: $300-$1,500), an iron & steel production facility may incur $1,051 (lower/upper bound: $400-$2,000), and a pulp and paper manufacturing facility may incur $1,051 (lower/upper bound: $400-$2,000). If a small business entity is a new reporter, they may incur an additional cost on training and planning for compliance with the regulation during the first year. The first-year-only cost is estimated to be $1,046 for a glass production facility, $3,137 for an iron & steel production facility, and $3,137 for a pulp & paper manufacturing facility.

Using a similar approach already described in the previous section to calculate average cost per company, the annual on-going yearly cost per small business is calculated to be $954 (($760+$1051+$1051)/3 companies), and the first-year-only cost is $2,440 (($1046+$3137+$3137)/3 companies).

4. Impacts to California State and Local Agencies

Staff has determined that the proposed amendments do not affect any GHG emitting facilities operated by state government entities (e.g., state universities and prison facilities). Nevertheless, those state government entities already subject to the GHG reporting program will continue to comply with the regulation requirements without noticeable changes in reporting practices. Using the methods described previously, we estimated that the affected local government entities will see an overall cost savings as the result of this proposal. Nine electricity generating facilities operated by local government entities are expected to see a cost saving of $4,900 per year (lower/upper bound: $2,500-$7,100 per year).

Adoption of the proposed amendments is expected to require continued funding for ARB to administer the program. The amendments will be implemented using existing ARB staffing, and no change in staffing level is needed to administer the program under the amended rule. Any ARB fiscal expenses needed for implementing the proposed amendments are already accounted for in the current operational budget that was approved as a part of the previous rule amendments.

5. Potential Impact on Consumers

No noticeable change in consumer prices is expected from the amendments to the reporting regulation because the compliance costs will have only a minor impact on the affected businesses. Since no economic impacts (either costs or savings) are expected to result from the conforming amendments to the definition sections of the Fee Regulation or the Cap-and-Trade Regulation, no change in consumer prices is expected from those regulation amendments either.

6. Impact on Employment

Since the incremental compliance costs associated with the amended GHG reporting regulation impose only a very small impact on California businesses, staff expects no significant change in employment due to the regulation amendments. Since no economic impacts (either costs or savings) are expected to result from the conforming amendments to the definition sections of the Fee Regulation or the Cap-and-Trade Regulation, staff expects no change in employment due to those regulation amendments either.

7. Impact on Business Creation, Elimination, or Expansion

No change is expected to occur in the status of California businesses as a result of the amendments to the reporting regulation. This is because the proposed amendments are expected to impose only minor costs on businesses in California. However, should the regulation impose significant hardship on California businesses operating with little or no margin of profitability, some small businesses may be forced out of the market or decide not to expand in California. Also, in theory, some businesses could possibly decide against coming to California to avoid having to report their GHG emissions.

Staff does not anticipate there will be noticeable changes in the number of businesses created, eliminated, or expanded as the result of the propose regulation. Existing firms will likely attempt to absorb as much of the new workload as possible, and the amount of spill-over available to new companies cannot be clearly determined.

Since no economic impacts (either costs or savings) are expected to result from the conforming amendments to the definition sections of the fee regulation or the cap-and-trade regulation, staff does not expect any impact on the status of California businesses to result from those regulation amendments either.

8. Impacts to California Business Competitiveness

The reporting regulation amendments would have little or no impact on the ability of California businesses to compete with businesses in other states. This is because the regulation does not impose a significant cost impact on California businesses. In addition, many of the businesses affected by the regulation are local businesses serving California clients, and may not be strongly subject to interstate competition. However, the proposed regulation could have an adverse impact on the ability of some California businesses operating with little or no margin of profitability to compete with businesses in other states. Similarly, since no economic impacts (either costs or savings) are expected to result from the conforming amendments to the definition sections of the fee regulation or the cap-and-trade regulation, staff does not expect any impact on the ability of California businesses to compete with businesses in other states due to those regulation amendments either.

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VII. SUMMARY AND RATIONALE FOR PROPOSED REGULATION

This chapter of the staff report provides a summary of each specific change to the regulations and the reason, or rationale, for the change. Any sections of the regulation without changes are not included in this summary and rationale section.

A. Amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions

Subarticle 1.
General Requirements for Greenhouse Gas Reporting

Summary of Section 95101, Applicability.

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

Summary of Sections 95101(a)(1)(A) and 95101(a)(1)(B) Proposed Updates
To clarify the applicability requirements, staff directly listed specific industry sectors subject to reporting, rather than incorporating applicability requirements of the U.S. EPA Greenhouse Gas Rule by reference. This change does not affect the numbers or types of reporters affected by the regulation.

Rationale for Sections 95101(a)(1)(A) and 95101(a)(1)(B) Proposed Updates
These amendments are necessary to improve clarity and usability of the regulation.

Summary of Sections 95101(a)(1)(B)(1) and 95101(b)(2) Proposed Updates
This amendment would require process emissions to be included in determining applicability for facilities emitting less than 10,000 metric tons of CO_2e.

Rationale for Sections 95101(a)(1)(B)(1) and 95101(b)(2) Proposed Updates
This requirement was already required for larger sources, emitting over 25,000 metric tons of CO_2e. The requirement was added for the smaller sources for consistency and to assist in GHG leakage and other analyses necessary for ARB greenhouse gas programs.

Summary of Section 95101(c)(5) Proposed Updates
The regulation was modified to also include importers of compressed natural gas and liquefied natural gas. This provision specifies that importers of compressed natural gas and liquefied natural gas must report pursuant to the regulation.

Rationale for Section 95101(c)(5) Proposed Updates
Staff inadvertently did not include compressed natural gas and liquefied natural gas importers in the previous amendments to the reporting regulation (ARB MRR 2010). The regulation change is necessary to correct this inequity in the reporting requirements and to ensure that all fuels that contribute to California GHG emissions are reported. It

is also necessary to ensure these importers understand the reporting requirements which apply to them.

Summary of Section 95101(e) Proposed Updates

The requirement to estimate and report process emissions for the 10,000 $MTCO_2e$ threshold and fugitive emissions for the 25,000 $MTCO_2e$ was added for petroleum and natural gas systems. This provision specifies that process and fugitive emissions must be estimated and reported by operators of petroleum and natural gas systems.

Rationale for Section 95101(e) Proposed Updates

This requirement was already required for larger sources emitting over 25,000 metric tons of CO_2e. The requirement was added for the smaller sources for consistency and to assist in GHG leakage and other analyses necessary for ARB greenhouse gas programs. The fugitive emission provision was a clarification to ensure consistency with section 95151(a)

Summary of Section 95101(e)(2) Proposed Updates

Reference to section 95102 for onshore petroleum and natural gas production facilities has been removed from the facility type list.

Rationale for Section 95101(e)(2) Proposed Updates

Other industrial sectors do not directly refer to the definition section of the regulation (95102(a)). Therefore, the definition reference for offshore petroleum and natural gas systems was removed for consistency and clarity.

Summary of Sections 95101(h)(1) and 95101(h)(2) Proposed Updates

Previously, the U.S. EPA regulatory text for cessation of reporting (40 CFR §98.2(i)) was incorporated in section 95101(h) by reference. The U.S. EPA text has now been written directly into the provisions of the ARB regulation. These provisions do not change any existing requirements.

Rationale for Sections 95101(h)(1) and 95101(h)(2) Proposed Updates

This update is necessary to improve the legibility of the cessation requirements. The change does not alter the previous regulatory requirements.

Summary of Section 95101(h)(4)(A)-(D) Proposed Updates

This provision specifies how electric power entities may cease reporting. Revisions were made to reduce ambiguity in the existing text for cessation of reporting for electric power entities, including clarification of what information must always be reported (i.e., retail sales and pump loads).

Rationale for Section 95101(h)(4)(A)-(D) Proposed Updates

This provision is necessary to clarify the cessation requirements for electric power entities, which are not subject to U.S. EPA reporting. The proposed revisions do not alter the existing cessation requirements for electric power entities, but are included to clarify the requirements and to make them more explicit.

Summary of Section 95102, Definitions.

This section defines all key terms used in the regulation that may not be in common use or which may potentially be ambiguous without a regulatory definition. Definitions have been edited, added, and in some cases, removed to clarify the meaning and intent of the regulation. In addition to the general changes to definitions, a subset of definitions associated with electric power entity reporting were updated, as described below. Also, with the addition of a new table to the regulation for fuel suppliers, definitions of the individual fuels were added to the regulation, also described below. Finally, with the inclusion of the full reporting requirements directly into the regulation for petroleum and natural gas systems reporting, associated definitions for this sector were added to the proposed regulation.

Rationale for Section 95102 Proposed Updates

This section is necessary to ensure that those subject to the regulation are able to understand and interpret the regulation correctly, and to avoid ambiguity and improve compliance with the regulation. ARB staff has attempted to include all key terms used in the regulation, including terms in the previously referenced U.S. EPA regulation, which are usually included without modification to support consistent interpretation of the state and federal regulation. Deletions, additions, and modifications from the current version of the reporting regulation are necessary to ensure clear interpretation of terms related to the other amendments to the regulation in this rulemaking.

Summary of Section 95103, Greenhouse Gas Reporting Requirements.
This section contains the reporting requirements for all facilities subject to this regulation, including abbreviated reporting, reporting and verification schedules, accuracy specifications, and other requirements. The specific revisions proposed are listed below.

Summary of Section 95103(a) Proposed Updates
A clarification to include fugitive emissions in the reporting requirements for determining the 25,000 $MTCO_2e$ reporting threshold was added.

Rationale for section 95103(a) Proposed Updates
This clarification was made to ensure reporters who have fugitive emissions include them when determining their emissions threshold for applicability and in their emissions data report.

Summary of Section 95103(a)(3) Proposed Updates
For specified industrial sectors emitting less than 25,000 metric tons of CO_2e per year, the requirement was added to calculate and report process emissions. This requirement is already required by sectors emitting more than 25,000 metric tons CO_2e. This change affects facilities involved in glass production, hydrogen production, iron and steel production, pulp and paper manufacturing, and petroleum and natural gas production (subarticle 5 of this regulation).

Rationale for Section 95103(a)(3) Proposed Updates

To maintain consistent reporting across sectors, it is necessary to include process emissions for certain facilities emitting less than 25,000 metric tons (MT) of CO_2e. Process emissions can be a significant fraction of the overall CO_2e emissions for some sectors, so their previous exclusion would create a discontinuity between the less than 25,000 MT CO_2e and the greater than 25,000 MT CO_2e facilities. In order to determine applicability (under the current requirement) process emissions must be computed, so the requirement does not substantially add to the reporting workload. The inclusion of the process emissions also provides data to better monitor GHG emissions leakage to out of state sources, which is necessary to provide more rigor in support of the cap-and-trade program.

Summary of Section 95103(a)(6) Proposed Updates

This provision has been amended to clarify that geothermal facilities must report data specified in section 95112(e).

Rationale for Section 95103(a)(6) Proposed Updates

This change simply clarifies the existing requirement for geothermal facilities to make it more explicit. It is necessary to ensure geothermal facilities understand their reporting obligations.

Summary of Section 95103(f) Proposed Updates

A clarifying term was added to this section to ensure it was clear that only reporting entities above 25,000 MTCO2e are subject to verification.

Rationale for Section 95103(f) Proposed Updates

This change is necessary to clarify the interpretation for which reporting entities are subject to verification.

Summary of Section 95103(j)(2) Proposed Updates

Clarifications have been added to this provision to specify the information that is required by reporters using forest derived wood and wood waste.

Rationale for Section 95103(j)(2) Proposed Updates

The proposed update is necessary to clarify that the required information relates to the supplier and not the consumer of the fuel.

Summary of Section 95103(k) Proposed Updates

The meter calibration requirements for covered emissions, covered product data and for data that is neither covered emissions or product data have been clarified. Language was added to explicitly indicate that all meters are subject to ± 5 percent accuracy, but meters that measure covered emissions and product data were subject to the additional requirements of this section. Clarifications were also added to indicate which meters are exempt or partially exempt from the requirements of 95103(k)(1)-(11).

Rationale for Section 95103(k)
During the implementation of the current reporting regulation, stakeholders expressed concerns about the interpretation of the requirements in section 95103(k) for both emissions and product data. The amendments described above clarify which types of meters are subject to the requirements section 95103(k)(1)-(11) and which meters must just meet the U.S.EPA requirements.

Summary of Section 95103(k)(1) Proposed Updates
The term "flow meter and other measurement device" was inserted, and language was inserted describing the term "meter or measurement device."

Rationale for Section 95103(k)(1) Proposed Updates
These changes are necessary to maintain consistent language throughout the section, and to clarify that a "meter or measurement device" consists of multiple components, and the measurement accuracy requirements in the section apply to the "meter" rather than to each individual component of a meter.

Summary of Section 95103(k)(2) Proposed Updates
The term "flow meter and other measurement device" was inserted in this provision.

Rationale for Section 95103(k)(2) Proposed Updates
These changes are necessary to maintain consistent language throughout the section.

Summary of Section 95103(k)(4) Proposed Updates
The term "flow meter and other measurement device" was inserted in this provision. In addition, this provision was modified to add a requirement of a recalibration of a flow meter or other measurement device immediately upon the device being deemed out of calibration.

Rationale for Section 95103(k)(4) Proposed Updates
These changes are necessary to maintain consistent language throughout the section. The requirement to recalibrate a meter or other measurement device immediately upon the device being deemed to be out of calibration was inserted to ensure the device is operating within the ± 5% accuracy range at all times.

Summary of Section 95103(k)(6) Proposed Updates
The terms "flow meter and other measurement device" and "field accuracy assessment" were added to this provision.

Rationale for Section 95103(k)(6) Proposed Updates
These changes are necessary to maintain consistent language throughout the section. The term "field accuracy assessment" was inserted in reference to new voluntary procedures in subparagraph B of section 95103(k)(6).

Summary of Section 95103(k)(6)(A) Proposed Updates
Language was inserted allowing for flow meters or other measurement devices to have alternative calibration methods approved by the Executive Officer in the event that OEM guidance is not available and methods specified in 40 CFR §98.3(i)(2)-(3) are not applicable to a particular device.

Rationale for Section 95103(k)(6)(A) Proposed Updates

The section was updated to provide reporting entities with the option to request approval of an alternative calibration procedure in the event that the required calibration methods specified in section 95103(k)(6) are not viable for a particular flow meter or measurement device. Requiring Executive Officer approval of alternative calibration procedures is necessary to ensure that any alternative calibration method will guarantee measurement within the ± 5% accuracy range. These changes are necessary to provide additional flexibility to reporting entities while also ensuring accuracy.

Summary of Section 95103(k)(6)(B) Proposed Updates

This new provision sets forth an option to allow an operator to perform a "field accuracy assessment" for mass and volume measurement devices. The field accuracy assessment is a voluntary procedure by which operators can confirm that meters and other measurement devices are continually measuring within the ± 5% accuracy range in years between successive calibrations. The provision allows for field accuracy assessments to be conducted using OEM guidance, standard industry practice, engineering analysis, or using portable calibration instruments with the as-found condition recorded to ensure the device is measuring within the ± 5% accuracy range. Performing a field accuracy assessment reduces the risk that a reporting entity will lose multiple years of data in the event of a failed calibration.

Rationale for Section 95103(k)(6)(B) Proposed Updates

Full calibrations of metering devices are required on a multi-annual schedule, in most cases every three years. This provision is necessary to provide an option for reporting entities to assess and document that meters and other measurement devices are operating within the ± 5% accuracy range during years between full calibrations. According the section 95103(k)(10), a failed calibration of a particular meter requires the operator to prove data accuracy by other means back to the previous successful calibration or field accuracy assessment. In the absence of a documented annual field accuracy assessment, the operator must demonstrate accuracy going back multiple years to the last successful calibration event. Failure to demonstrate accuracy may result in the invalidation of the data. The field accuracy assessment procedure enables reporting entities to manage data risks associated with failed calibrations by providing an annual "confirmation" that meters are operating within the ± 5% accuracy range.

Summary of Section 95103(k)(6)(C)

This new provision describes the options and consequences for a reporting entity that fails a calibration in cases of just performing calibrations or in the case of performing calibrations and the field accuracy assessment. If a meter fails calibration, the data back to the original calibration is deemed invalid and the reporter must demonstrate, by other means, that the data was accurate up to a certain point. If a meter fails calibration, but has a valid field accuracy assessment, then the data is invalid until the last valid field accuracy assessment.

Rationale for Section 95103(k)(6)(C)
This new provision clarifies the consequences if a meter fails calibration and describes steps that need to be taken to demonstrate accuracy. It was added to ensure reporting entities are clear on the measurement accuracy requirements.

Summary of Section 95103(k)(7) Proposed Updates
This provision was modified to clarify exemptions to the specified requirements in section 95103(k). The section describes instances when financial transaction meters and upstream ethanol and additive meters used for ensuring proper blendstock percentages are exempt from specified calibration requirements in section 95103(k).

Rationale for Section 95103(k)(7) Proposed Updates
The changes made to this provision are necessary to clarify that meters that are used as a basis for third-party financial transactions or used for ensuring proper blendstock of finished gasoline products must be designed, installed, and maintained in a manner that ensures highly accurate data out of necessity for purposes other than GHG emissions estimation. In addition, the changes are needed to inform reporting entities of which circumstances will exempt certain meters from the more stringent calibration requirements.

Summary of Section 95103(k)(9) Proposed Updates
This provision describes the process for submitting calibration postponement requests for devices that cannot be calibrated without operational disruption. Requirements were added to require that dates and results of field accuracy assessments be included in the postponement request.

Rationale for Section 95103(k)(9) Proposed Updates
Requiring disclosure of a meter's field accuracy assessment schedule and results in the postponement request provides evidence that the meter is being operated and maintained in a manner ensuring performance within the acceptable accuracy range. Therefore this information is necessary for ARB staff to evaluate a calibration postponement request.

Summary of Section 95103(k)(10) Proposed Updates
A provision was added to this section requiring that, in the event a device fails a calibration, recalibration, or field accuracy assessment, the operate must demonstrate by other means that measurements meet the accuracy requirements going back to the last instance of successful calibration or field accuracy assessment of the device.

Rationale for Section 95103(k)(10) Proposed Updates
This provision is necessary to clarify the requirements for demonstrating data accuracy in the event of a failed calibration or field accuracy assessment. The new provision requires that accuracy be demonstrated back to the last successful field accuracy assessment or calibration. This provision allows operators to mitigate the risk of data loss due to a failed calibration by performing annuals field accuracy assessments.

Summary of Section 95103(k)(11) Proposed Updates
This provision was revised to clarify that inventory, stock, or tank drop measurement methods must be demonstrated to be accurate to ± 5% annually for covered product data.

Rationale for Section 95103(k)(11) Proposed Updates
This revision is necessary to clarify that inventory, stock, and tank drop measurement methods are applicable for measuring covered product data if they are accurate annually to ± 5%.

Summary of Section 95103(l) Proposed Updates
This provision was amended to indicate that covered product data is subject to the material misstatement requirements, while other reported product data is only subject to conformance.

Rationale for Section 95103(l) Proposed Updates
This revision is necessary to ensure that only covered product data is subject to the material misstatement evaluation.

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

Summary of Section 95104(a) Proposed Update
This provision specifies what information must be included in the GHG emissions data reports. The amendments add a requirement for reporting entities to indicate whether they qualify for small business status pursuant to California Government Code Section 11342.610.

Rationale for Section 95104(a) Proposed Updates
This provision is added to collect information about small business entities that are covered by the GHG reporting program. This provision is necessary to help ARB assess the economic impacts of the GHG reporting program, the cap-and-trade program, and the fee regulation.

Summary of Section 95105, Record Keeping Requirements,

Summary of Section 95105(d)(6) Proposed Updates
This provision specifies how verifiers need to evaluate electric power entities for covered emissions, the RPS adjustment and qualified export reporting requirements.

Rationale for Section 95105(d)(6) Proposed Updates
As previously written, the regulation could have been interpreted in such a way to require verification of data beyond the scope of the reporting needs. The amendments to this provision are necessary to ensure that reporters and verifiers understand GHG inventory requirements for electric power entities.

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

Summary of Section 95111, Electric Power Entities.

Section 95111 describes the reporting requirements for electric power entities. Electric power entities include importers, marketers, retail providers and asset controlling suppliers who are involved in electricity transactions.

Summary of Section 95111(a)(5) Proposed Updates
This provision specifies requirements for asset-controlling suppliers. It has been amended to remove the specific references to Bonneville Power Administration in this section. This section was also amended to clarify that the asset-controlling supplier must be identified on the physical path of NERC e-Tag as the PSE at the source of generation to ensure that the power originated from the asset-controlling supplier.

Rationale for Section 95111(a)(5) Proposed Updates
The text referring to Bonneville Power Administration (BPA) was removed to ensure equitable treatment of all asset-controlling suppliers. Clarifying language, regarding the source of generation listed in the physical path table of NERC e-Tags, was added to ensure that power claimed from an asset-controlling supplier source originated from the asset-controlling supplier. This change also supports the requirement that electricity from an asset-controlling supplier must be separately reported in the annual emissions data report.

Summary of Section 95111(a)(8) Proposed Updates
This provision was amended to clarify the reporting requirements of wheeled electricity. In the current reporting regulation, wheeled electricity needed to be reported by the first point of receipt outside of California. The term 'outside of California' was removed to indicate that reporting for wheeled electricity needs to occur at the first point of receipt.

Rationale for Section 95111(a)(8) Proposed Updates
This revision is necessary to ensure the correct point of receipt is reported for wheeled electricity in the emission data report of an electric power entity.

Summary of Section 95111(b)(2) Proposed Update
A description of the specified source emission factor data sources was included. It was clarified that the specified source emission factor is based on data from the year prior to the data year.

Rationale for Section 95111(b)(2) Proposed Updates
This revision is necessary to clarify the data used to calculate the specified source emission factor.

Summary of Section 95111(b)(3) Proposed Updates
This provision specifies how GHG emissions are calculated for Importers of electricity supplied by specified asset-controlling suppliers. It has been amended to remove specific references to Bonneville Power Administration and its system emission factor, and to clarify that asset-controlling suppliers may be any entity which meets the requirements of this section and the regulation, and which is recognized by ARB. The proposed changes are intended to describe the asset-controlling supplier registration process, rights, and obligations in the regulation, to ensure identical process and equitable treatment for any asset-controlling supplier, and maintain a separate list of authorized asset-controlling suppliers on the ARB website. The revisions also indicate that the asset-controlling supplier system-specific emission factor is calculated based on data from two years prior to the reporting year.

Rationale for Section 95111(b)(3) Proposed Updates
Upon approval of the regulation in 2010 there was one asset-controlling supplier recognized by ARB, Bonneville Power Administration (BPA), which was specifically named as an asset-controlling supplier in Section 95111(a)(5). However, the regulation does not limit the number of asset-controlling suppliers that may register for approval with ARB. Since adoption of the regulation, additional stakeholders have expressed interest in being recognized as asset-controlling suppliers and submitting reports that would subject them to the full requirements of the regulation. To ensure equitable treatment of all asset-controlling suppliers, ARB proposes to remove BPA's currently published emission factor and require an annual calculation of all asset-controlling suppliers' system emission factors. The proposed changes are necessary to describe the asset-controlling supplier registration process, rights, and obligations in the regulation, to ensure identical process and equitable treatment for any asset-controlling supplier, identify the asset-controlling supplier system emission factor method, and maintain a separate list of authorized asset-controlling suppliers on the ARB website.

Summary of Section 95111(b)(5) Proposed Updates
A minor language change was added for more consistency with the cap-and-trade regulation and the equation was added under the correct variable description.

Rationale for Section 95111(b)(5) Proposed Updates
These changes were made to correct small errors found in the current reporting regulation.

Summary of Section 95111(c) Proposed Updates
This provision was amended to remove the text "GHG Emissions Data Report" from the title.

Rationale for Section 95111(c) Proposed Updates
This amendment is necessary to avoid having redundant language.

Summary of Section 95111(c)(4) Proposed Updates
Language was added to ensure completeness in retail provider emissions data reports.

Rationale for Section 95111(c)(4) Proposed Updates

The purpose of this provision is to ensure that all electricity imported by either the retail provide, or by another entity on behalf of the retail provider, is reported. Language regarding imported electricity was added to ensure retail providers reported all imports, including imports on their behalf. Also, the text, "or exporters," was added so as to be consistent with the use of both "importers" and "exporters" in tandem, as is done in other areas of the regulation.

Summary of Section 95111(d)-(e) Proposed Updates

This provision has been amended to remove the text "GHG Emissions Data Report" from the title.

Rationale for Section 95111(d)-(e) Proposed Updates

This amendment is needed to reduce redundancy.

Summary of Section 95111(f) Proposed Updates

This provision was amended to clarify the requirements for asset-controlling suppliers. Additional language in the first paragraph was added to clarify who may apply for the asset-controlling supplier designation. Specific references to Bonneville Power Administration have been removed. Application requirements in sections 95111(f)(1) and (5) have been added. The application requirement additions for asset-controlling suppliers include general business information, specific reporting requirements, and an attestation indicating that their data report is accurate and complete. It was also made explicitly clear that asset-controlling suppliers must report and verify on an annual basis.

Rationale for Section 95111(f) Proposed Updates

The original regulation did not limit the number of asset-controlling suppliers that may register for approval with ARB, but additional clarification and process provisions are necessary to ensure reporting entities interested in applying for asset-controlling supplier designation understand the process for doing so. In fact, the revisions to this provision were added in response to stakeholders that have expressed interest in being recognized as asset-controlling suppliers.

Summary of Section 95111(g) Proposed Updates

This provision was amended to add subsection requirement (M) to the *Registration Information for Specified Sources and Eligible Renewable Energy Resources in the RPS Adjustment*, which would require an electric power entity to provide the serial numbers of their Renewable Energy Credits (REC) as part of the registration process.

Rationale for Section 95111(g) Proposed Updates

This revision is necessary for ARB to track and ensure the RECs used for the RPS adjustment are correctly tied to the electricity that is reported under this article.

Summary of Section 95112, Electricity Generation and Cogeneration Units.

Summary of Section 95112 Proposed Updates
This provision specifies the requirements for electricity generation and cogeneration units. The section has been amended to require reporters who report energy data using engineering estimation to demonstrate accuracy of their chosen estimation approach.

Rationale for Section 95112 Proposed Updates
The additional requirements are necessary to provide sufficient data quality for the state-wide inventory without the full metering and 5% accuracy requirements that are placed on data used for calculating cap-and-trade covered emissions. It gives a standard for reviewing engineering estimations, which should not be prescriptive due to the large variations in facility set-up, and still helps reduce costs to facility operators.

Summary of Section 95112(a)(4)(B) Proposed Updates
This provision has been modified to point readers to the definition of "particular end-user" in section 95102.

Rationale for Section 95112(a)(4)(B) Proposed Updates
This provision is needed to point readers to the definition of "particular end-user" to assist correct reporting. This is important to clarify questions received during implementation of the existing regulation from reporting entities and accredited verifiers.

Summary of Section 95112(a)(5)(A) Proposed Updates
This provision has been amended to point readers to the definition of "particular end-user" in section 95102.

Rationale for Section 95112(a)(5)(A) Proposed Updates
This provision is needed to ensure readers look to the correct definition of "particular end-user" to assist them in reporting correctly.

Summary of Section 95112(a)(5)(B) Proposed Updates
This provision was amended to clarify that steam directly used for power production is not included in the calculation of thermal energy used for supporting power production.

Rationale for Section 95112(a)(5)(B) Proposed Updates
This provision is necessary to clarify what inputs go into calculating thermal energy for supporting power production.

Summary of Section 95112(b) Proposed Updates
Rule language has been added to this provision to clarify that the aggregation criteria in sections 95115(h) and 95112(b) take precedence over U.S. EPA's unit aggregation criteria in 40 CFR §98.36(c)(1)-(4) and (d)(1)(i). Rule language was also added to allow facility operators to aggregate all the units that are integrated into an electricity generation system. For other electricity generating units that are not a part of an electricity generation system, aggregation is limited to units of the same type.

Rationale for Section 95112(b) Proposed Updates
These changes are necessary to clarify the rule requirements and allow the operators to aggregate units and report the entire system as one configuration in the reporting tool. The change is made in response to questions and feedback from reporting entities and accredited verifiers. The change is necessary because often times in an integrated system, the units that combust fuel are not the same units that generate electricity and steam, and the units that generate electricity and steam do not necessary consume any fuel. It is often difficult to report steam output if there is no one-to-one relationship between fuel combusting unit and steam generation unit. The implementation of this provision will also streamline data analysis for ARB staff when working with the state-wide inventory data.

Summary of Section 95112(b)(1)(B) Proposed Updates
The spelling of "primer" has been changed.

Rationale for Section 95112(b)(1)(B) Proposed Updates
This change is needed to correct a typo in the term "primer."

Summary of Section 95112(b)(3) Proposed Updates
This provision was amended to point readers to the definition of "total thermal output" in section 95102, and to indicate that "steam used to drive a steam turbine generator for electricity generation" is also excluded from the quantity to be reported under this sub-paragraph.

Rationale for Section 95112(b)(3) Proposed Updates
These amendments are necessary to assist in correct reporting and to clarify that steam used to drive a steam turbine generator for electricity generation should be excluded from the "total thermal output" quantity.

Summary of Section 95112(b)(5) Proposed Updates
The 40 CFR §98.36(b) reference has been changed.

Rationale for Section 95112(b)(5) Proposed Updates
This change is needed to correct a typo in the reference to 40 CFR §98.36(b).

Summary of Section 95112(b)(7)
This provision was amended to add reporting requirements for separate reporting of heat input from primary fuels and supplemental fuels.

Rationale for Section 95112(b)(7)
The new reporting requirement is necessary for the purpose of compiling the state-wide emissions inventory and calculating the carbon intensity of electricity generated in-state.

Summary of Section 95112(b)(8)
This provision specifies requirements for reporting heat input. It has been amended to require reporting of additional heat input that is not already account for by direct fuel consumption. In addition, the provision has been amended to add two additional data items for bottoming cycle cogeneration unit: input steam to steam turbine and the output of heat recovery steam generator.

Rationale for Section 95112(b)(8)
The amendments are necessary to capture a complete energy balance of the electricity generation system for understanding system efficiency and carbon intensity of in-state electricity. The two additional data items for bottoming cycle cogeneration system are necessary for ARB staff to calculate the carbon intensity of in-state electricity for inventory purpose.

Summary of Section 95113, Petroleum Refineries.

Summary of Section 95113(l)(1) Proposed Updates
This provision was amended to add calcined coke reporting requirements. In addition, calcined coke is considered a covered product data because the reported data is used for the allocation of allowances under the cap-and-trade regulation. The voluntary reporting of 2011 and 2012 product data for calcined coke was added. If a reporting entity chooses to report their 2011 and 2012 product data in by April 10, 2013, they must get the reported data verified.

Rationale for Section 95113(l)(1) Proposed Updates
The revision is necessary to ensure petroleum refineries received their correct allocations under the cap-and-trade program.

Summary of Section 95113(l)(2) Proposed Updates
This provision was amended to delete a requirement related to previous data years. The deleted text is no longer needed.

Rationale for Section 95113(l)(2) Proposed Updates
This revision is necessary because the deleted text is no longer applicable.

Summary of Section 95114, Hydrogen Production.

Summary of Section 95114(i) Proposed Updates
This provision was amended by adding language to prevent double counting of emission in cases where a hydrogen production facility captures CO_2 and then sells the CO_2.

Rationale for Section 95114(i) Proposed Updates
As the regulation is currently written, emissions from hydrogen plants CO_2 may potentially be reported under two separate components of the regulation. The revision is necessary to prevent this double-counting of the CO_2 emissions by requiring the subtraction of "transferred CO_2" for hydrogen plants that also are subject to reporting as a Supplier of CO_2.

Summary of Section 95114(j) Proposed Updates
Text has been added to this provision to clarify product data reporting requirements for hydrogen plants and to specify that hydrogen produced is to be reported as both liquid and gaseous components, and to indicate if the hydrogen is produced as part of an integrated refinery operation.

Rationale for Section 95114(j) Proposed Updates
In order to ensure that the cap-and-trade program can correctly allocate emissions allowances based on reported product data in this sector, and to evaluate leakage, it was necessary to amend this reporting requirement to include the quantities of both liquid and gaseous hydrogen produced, rather than just the liquefied hydrogen, as previously written. The type of hydrogen operation (stand-alone versus integrated into a refinery) is also needed for cap-and-trade allowance allocation.

Summary of Section 95115, Stationary Fuel Combustion Sources.

Summary of Section 95115(c)(2) Proposed Updates
This provision was modified to clarify that Tier 1 can be used to calculate CO_2 if fuel is measured in either therms or million Btu.

Rationale for Section 95115(c)(2) Proposed Updates
As originally written, only therms were identified for use with Tier 1. This caused ambiguity for reporters who had data in units of million Btu (MMBtu). A therm is simply 10,000 btu, therefore data measured as either therms or MMBtu is acceptable under the regulation. This change is necessary to improve clarity and to ensure consistency in terminology with the U.S. EPA GHG regulation.

Summary of Section 95115(c)(4) Proposed Updates
This provision was modified to indicate that non-pipeline quality natural gas must use a Tier 3 and Tier 4 calculation method.

Rationale for Section 95115(c)(4) Proposed Updates
This clarification is necessary to ensure accurate data is reported for non-pipeline quality natural gas.

Summary of Section 95115(e)(3) Proposed Updates
Typographical errors were corrected for the equation used for calculating emissions from a biomethane and natural gas mixture. These revisions do not affect any reporting requirements. A term in the equation was mislabeled, and a description of a term was provided that is not used in the equation.

Rationale for Section 95115(e)(3) Proposed Updates
The corrections are necessary to clarify the equation and ensure accurate use of the calculation procedures.

Summary of Section 95115(h) Proposed Updates
The edited text conforms with the amended text in section 95101(a)(1)(A)-(B). The rule change limits unit aggregation to units that belong to the same source category (as defined by the various subparts in 40 CFR Part 98), such that Subpart C units cannot be aggregated with units that belong to other subparts. The rule change also limits aggregation of Subpart C units to four unit types: boiler, reciprocating internal combustion engines, turbine, and process heater. In addition, it requires that facility

operators that choose to aggregate units using U.S. EPA's common stack provision to still report fuel use (in MMBtu) by fuel type for State-wide inventory purposes.

Rationale for Section 95115(h) Proposed Updates
The first rule edit in this paragraph is necessary to match the references to the amended text in 95101(a)(1)(A)-(B). Other changes to the rule text that limit unit aggregation to units that belong to the same source category and unit type were made to ensure that the state-wide GHG inventory collects information in sufficient details to delineate the emissions by unit types and fuel types. These changes do not affect the overall emissions reported through the GHG reporting program.

Summary of Section 95119, Pulp and Paper Manufacturing.

Summary of Section 95119(d) Proposed Updates
A clarification was provided for reporting product data for pulp and paper production to specify that product data are to be reported as "air dried" tons.

Rationale for Section 95119(d) Proposed Updates
This minor clarification is necessary to ensure consistent reporting by specifying that paper product data is reported with a standard "air dried" 6 percent moisture content, as defined in section 95102 of the regulation.

Summary of Section 95120, Iron and Steel Production.

Summary of Section 95120(a) Proposed Updates
This provision was amended to correct a reference to the U.S. EPA GHG reporting regulation.

Rationale for Section 95120(a) Proposed Updates
This amendment is necessary to correct a minor ambiguity in the text. The section numbers referenced in the text clearly referred to the U.S. EPA regulation, but the amendment makes the reference more explicit.

Summary of Section 95120(d) Proposed Update
This provision was amended to remove the term "primary" from iron and steel products.

Rationale for Section 95120(d) Proposed Update
This amendment is necessary to ensure consistent terms are used when collecting product data for the allocation of allowances.

Summary of Section 95121, Suppliers of Transportation Fuels.

References to U.S. EPA Tables MM-1 and MM-2, showing fuels subject to reporting, were removed from the regulations and the those fuels subject to reporting were directly inserted into the ARB regulation as new Table 2. The proposed updates include both text edits to the sections shown (which remove the U.S. EPA references), as well as the addition of Table 2 and associated references.

Rationale for Section 95121 Proposed Updates
These proposed revisions, which affect several subsections, improve the legibility and ease of use of the regulation because it is no longer necessary to reference an outside document to determine which supplied fuels must be reported. The change also simplifies the previous ARB language which included certain exceptions to the U.S. EPA tables, which are now more efficiently addressed by the addition of the ARB Table 2.

Summary of Section 95121(a)(2) Proposed Updates
The section was modified to make it clear that fuels which have a final destination outside of California are not subject to reporting.

Rationale for Section 95121(a)(2) Proposed Updates
This change was necessary to make it more explicit that fuels exported outside of California are not subject to reporting. The change does not alter any existing requirements.

Summary of Section 95121(b)(1) Proposed Updates
This provision was modified to better emphasize that emissions are based on fuel removed from the rack.

Rationale for Section 95121(b)(1) Proposed Updates
The edit is needed to clarify that emissions are to be based on fuel removed from the rack. The change does not alter any existing reporting requirements.

Summary of Section 95121(d) and Table 2 Proposed Updates
This provision was amended to reference newly added Table 2, which is a restatement of what was included in the incorporated provision from 40 CFR Part 98. Staff has included Table 2 to directly specify which fuels must be reported, rather than relying on a provision from 40 CFR Part 98 which was incorporated by reference.

Rationale for Section 95121(d) and Table 2 Proposed Updates
This amendment is needed to refer to the new table which is added to section 95121. Table 2 is needed to allow reporting entities to know which fuels to report under this provision.

Summary of Section 95122, Suppliers of Natural Gas, Natural Gas Liquids, and Liquefied Petroleum Gas, Compressed Natural Gas, and Liquefied Natural Gas.

Summary of Section 95122(a)(3) Proposed Updates
In the previous version of the regulation, importers of compressed natural gas and liquefied natural gas were omitted. In the amended version of the mandatory reporting regulation, they have been added. This provision specifies which GHGs importers of compressed natural gas and liquefied natural gas are required to report.

Rationale for Section 95122(a)(3) Proposed Updates
These revisions are necessary to provide consistency in reporting for suppliers, including the complete suite of potential fuels with the addition of compressed natural gas and liquefied natural gas.

Summary of Section 95122(b)(9)-(10) Proposed Updates
Related to the item above, the edits in these two sections provide the specific methodologies which must be used in estimating emissions associated with imports of compressed natural gas and liquefied natural gas.

Rationale for Section 95122(b)(9)-(10) Proposed Updates
The methods provided for the newly added fuels are needed to ensure consistent reporting and are based on existing U.S. EPA methodologies included in the ARB regulation.

Summary of Section 95122(d)(5)Proposed Updates
This provision was modified to discriminate between natural gas and natural gas liquids reporting requirements.

Rationale for Section 95122(d)(5) Proposed Updates
This clarification is needed to ensure natural gas and natural gas liquids are reported correctly in this article.

Summary of Section 95122(f) Proposed Updates
This section was removed and moved, with modification, to section 95156(d).

Rationale for Section 95122(f) Proposed Updates
This deletion was needed to ensure the correct reporting entities were reporting this product data.

Summary of Section 95123, Suppliers of Carbon Dioxide.

Summary of Section 95123(b) Proposed Updates
The reference to the U.S. EPA rule was updated to reflect the correct section.

Rationale for Section 95123(b) Proposed Updates
This provision is needed to ensure suppliers of carbon dioxide are directed to the correct U.S.EPA rule citation.

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

This subarticle includes additions and modifications to the existing verification requirements of the current ARB GHG reporting regulation. These additions and modifications are summarized below, and an explanation of their necessity is also included. Provisions which have been retained and are not modified are not described below.

Summary of Section 95130, Requirements for Verification of Emission Data Reports.

This section clarifies the existing requirements for verification of emission data reports.

Summary of Section 95130 Proposed Updates
This provision was amended to resolves an inconsistency between the verification applicability requirements specified in section 95103(f) and section 95130 of the regulation.

Rationale for Section 95130 Proposed Updates
This change is necessary because section 95103(f) specifies that verification is required by facilities meeting certain requirements. Section 95130 included wording that was inconsistent with these requirements. Specifically, 95130 required verification by certain facilities emitting less than 25,000 metric tons of CO_2e that are not subject to abbreviated reporting. The proposed revision to section 95130 now accurately reflects staff intent, and the requirements triggering verification are confined to section 95103(f).

Summary of Section 95131, Requirements for Verification Services.

This section clarifies the existing requirements for verification services.

Rationale for Section 95131 Proposed Updates
Changes are needed to clarify the sector specialty provisions for verification services and the emissions data report modifications provision. In addition, changes are needed to the verification provisions for product data to support the cap-and-trade program.

Summary of Section 95131(a)(2) Proposed Updates
This provision describes the requirements for verification teams to include accredited sector specific verifiers as part of the verification team.

Rationale for Section 95131(a)(2) Proposed Updates
These changes are necessary to remove redundancies due to the addition of definitions of sector specialist verifiers in Section 95102(a).

Summary of Section 95131(b)(3) Proposed Updates
This paragraph describes the requirements for site visits performed by verification bodies as part of full verification services.

Rationale for Section 95131(b)(3) Proposed Updates
The term "sector specialist" was changed in this paragraph in order to be consistent with the proposed newly defined term "sector specific verifier."

Summary for 95131(b)(7)(B) Proposed Updates
This provision addresses requirements for the sampling plan. It has been modified to remove the requirement that any single product data component needs to be included in the sampling plan.

Rationale for Section 95131(b)(7)(B) Proposed Updates
These changes are necessary to provide consistency with the new treatment of product data reporting in section 95103(k).

Summary for 95131(b)(9) Proposed Updates
Emissions data report modifications are required, where possible, subject to this provision. It has been amended to clarify that failure to make required report modifications will result in an adverse verification statement.

Rationale for Section 95131(b)(9) Proposed Updates
These changes are necessary to clarify and add consistency with the existing definition of "adverse verification statement" in section 95102(a). The change clarifies that an adverse verification statement will result if a reporting entity does not make corrections to reported data errors, when required.

Summary for Section 95131(b)(10) Proposed Updates
This provision addresses findings of material misstatement. The requirement to evaluate material misstatement of single product data components was removed.

Rationale for Section 95131(b)(10) Proposed Updates
The requirement to evaluate material misstatement of single product data components was removed in order to ensure consistency with the proposed text to evaluate material misstatement based on "total covered product data" in paragraph 95131(b)(12).

Summary for Section 95131(b)(12) Proposed Updates
This provision and subparagraph have been updated to reflect evaluation of "total covered product data." Additionally, the equation to determine material misstatement has been divided into two equations: one for emissions data and the second for product data.

Rationale for Section 95131(b)(12) Proposed Updates
The changes are needed to support the cap-and-trade program's direct allocations which are based on "total covered product data" summed for each facility or supplier and not based on individual "single product data components."

Summary of Section 95131(i)(1)(C)(3) Proposed Updates
This provision applies to verification of biomass-derived fuels and specifies which information from biomass-derived fuels is considered an omission in the evaluation for material misstatement.

Rationale for Section 95131(i)(1)(C)(3) Proposed Updates
Amendments to this provision are needed to improve clarity in the regulatory text. The changes do not alter the original regulatory intent or requirements.

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

Summary of Section 95132(b)(5)(B) Proposed Updates
The citation for the cap-and-trade regulation is corrected in this paragraph.

Rationale for Section 95132(b)(5)(B) Proposed Updates
The citation for the cap-and-trade regulation is corrected in this paragraph and is necessary for clarity.

Summary of Section 95132(c) Proposed Updates
All references to "offset project verifiers" were changed to the proposed newly defined term "offset project specific verifier" which appears in section 95102(a).

Rationale for Section 95132(c) Proposed Updates
These changes are needed for consistency with the proposed newly defined term "offset project specific verifier."

Summary of Section 95133, Conflict of Interest Requirements for Verification Bodies for Emissions Data Reports.

This section provides for conflict of interest disclosure and evaluation required for ARB-approval of verification services.

Summary of Section 95133(b) Proposed Updates
Updates in this section include changing the time-frame to 5 years for consistency with other provisions of the regulation and removing redundancy from the regulation text.

Rationale for Section 95133(b) Proposed Updates
The term "non-verification" was deleted, as there is no need to categorize verification services versus non-verification services in this context. The high conflict services are clearly described in this paragraph.

Summary of Section 95133(c) Proposed Updates
This paragraph was reorganized to clarify the original intent: verifications performed outside of ARB jurisdiction are excluded from the financial assessment. These services must be disclosed, but are not part of the conflict of interest evaluation of non-verification services.

Rationale for Section 95133(c) Proposed Updates
These changes are needed to clarify ARB's intent and improve consistency in verifier application of the provision.

Summary of Section 95133(e) Proposed Updates
Text in this section regarding conflict of interest submittal requirements for accredited verification bodies was edited to provide for internal consistency with references to "reporting entities and related entities" as well as "verification bodies and related entities."

Rationale for Section 95133(e) Proposed Updates
These edits are needed to provide for internal consistency and to reflect a common interpretation.

Summary of Section 95133(e)(1)(B) Proposed Updates
This provision clarifies that verification bodies are permitted to perform verification services for the reporting entity, outside of the jurisdiction of ARB, so long as the verification body discloses this information to ARB.

Rationale for Section 95133(e)(1)(B) Proposed Updates
These edits are needed to provide for internal consistency and to reflect a common interpretation.

Summary of Section 95133(e)(1)(C) Proposed Updates
This provision provides for disclosure of services provides by the verification team, verification body and related entities to the reporting entity and its related entities. Language consistency was improved, as well as keeping time-frames consistent throughout subarticle 4 of the regulation.

Rationale for Section 95133(e)(1)(C) Proposed Updates
The scope of disclosure is clarified as including activities of the verification body. The term "non-verification services" is deleted to improve clarity in this context and "services other than ARB verification services" is added in its place. The time frame of 3 years is changed to 5 years for consistency with other provisions in this section. The scope of disclosure is extended to the reporting entity's related entities to ensure consistency with other provisions in this section. Reference to "accounting of GHG emissions or electricity or fuel transactions" did not provide clarity and has been deleted. Reference to "related to GHGs or electricity transactions" is unneeded and is deleted, since a broader scope is consistent with the context in this section.

Summary of Section 95133(f)(4) Proposed Updates
Edits were made to this provision to clarify that the scope of conflict of interest determination includes the reporting entity's related entities and the verification body's related entities. "Related entity" is defined pursuant to section 95133(b)(2).

Rationale for Section 95133(f)(4) Proposed Updates
These edits were necessary to clarify that the scope of conflict of interest determination includes the reporting entity's related entities and the verification body's related entities.

Summary of Section 95133(g)
This provision describes ongoing requirements for monitoring conflict of interest situations. These edits were made to clarify that the scope of conflict of interest monitoring includes the reporting entity's related entities and to clarify that financial disclosure is required.

Rationale for Section 95133(g) Proposed Updates
These changes are necessary to provide improved rigor to conflict of interest monitoring requirements.

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

Summary of Sections 95150-95158 Proposed Updates.

The current ARB regulation included U.S. EPA requirements incorporated by reference which spanned several U.S. EPA rule packages for 40 CFR Part 98, resulting in some confusion by reporting entities in understanding their reporting obligations. In order to improve the clarity of this subarticle, ARB has proposed to insert directly into the regulation the majority of the incorporated text, and to no longer simply rely on incorporation by reference. As such, this subarticle has been modified to specifically list out the requirements from the U.S. EPA rules in the ARB regulation. For the most part, these requirements are identical to those incorporated by reference in the 2010 revisions, but in some cases the equations have changed and these changes are discussed below. Additionally, for those specific provisions which are different from the U.S. EPA text, ARB staff will provide more detailed summary and rationale below.

Rationale for Sections 95150-95158 Proposed Updates
The amendments to sections 95150-95158 specifically list out the provisions of the U.S. EPA's 40 CFR Part 98 and are necessary to reduce confusion, improve clarity, and ensure that reporting entities are fully aware of their reporting obligations under the ARB reporting regulation. The rationale included in the ARB MRR 2010 ISOR still apply to these provisions.

Summary of Section 95150(a)(2) Proposed Updates
The language "associated with a single well pad," which is included in the U.S. EPA's most recent rule update was not added to these amendments. Instead, the language "associated with a well pad" was used.

Rationale for Section 95150(a)(2) Proposed Updates
This provision is needed to ensure the facility boundaries, for purposes of the cap-and-trade program, are sufficient to collect the required emissions for onshore petroleum and natural gas production facilities.

Summary of Section 95152(c) Proposed Updates
One additional reporting requirement was added for the onshore petroleum and natural gas production industry segment. This industry segment is now required to report emissions related to equipment and pipeline blowdowns using the methods found in section 95153(g). Additionally, the reporting requirement for equipment leaks was changed for this industry segment. Previously reporters used the methods in section 95153(p) which requires equipment population counts and use of a default emissions factor. This reporting requirement has been deleted and reporters are now required to use the methods found in 95153(o) - Leak detection and leaker emission factors. Reporting requirements were also added for hydrocarbon liquids dissolved CH_4 and CO_2 (section 95153(v)). The requirements added in section 95153(v) replace the storage tank requirements in 95153(h).

Rationale for Section 95152(c) Proposed Updates
The requirement to report GHG emissions from equipment and pipeline blowdowns is necessary to provide a more complete emissions accounting for this sector. Use of the leaker screening methodology (95153(o)) is necessary to provide operators with actionable information to address and fix leaking components and to provide more accurate emissions data reporting to support the statewide greenhouse gas inventory program. Inclusion of the emissions methodology for hydrocarbon dissolved CH_4 and CO_2 is necessary to capture the emissions that occur when produced hydrocarbons are brought to atmospheric pressure and the dissolved GHGs escape as produced hydrocarbons are transported from the production field to refinery.

Summary of Section 95152(e) Proposed Updates
Language was added to require reporting of flaring emissions for the onshore natural gas transmission compression industry segment.

Rationale for Section 95152(e) Proposed Updates
This provision is necessary to ensure the reporting of flares from the industry segments in this subarticle are accurately accounted for.

Summary of Section 95152(f) Proposed Updates
Language was added to require reporting of flaring emissions for the underground natural storage industry segment. Language was also added to require reporting of equipment and pipeline blowdown emissions.

Rationale for Section 95152(f) Proposed Updates
This provision is necessary to ensure the reporting of flares from the industry segments in this subarticle are accurately accounted for. The inclusion of equipment and pipeline blowdown emissions is necessary to provide a more complete picture of GHG emissions from this industry segment for the greenhouse gas inventory.

Summary of Section 95152(g) Proposed Updates
Language was added to require reporting of flaring emissions for the LNG storage industry segment. Language was also added to require reporting of equipment and pipeline blowdown emissions.

Rationale for Section 95152(g) Proposed Updates
This provision is necessary to ensure the reporting of flares from the industry segments in this subarticle are accurately accounted for. The inclusion of equipment and pipeline blowdown emissions is necessary to provide a more complete picture of GHG emissions from this industry segment for the greenhouse gas inventory.

Summary of Section 95152(h) Proposed Updates
Language was added to require reporting of flaring emissions for the LNG import/export industry segment.

Rationale for Section 95152(h) Proposed Updates
This provision is necessary to ensure the reporting of flares from the industry segments in this subarticle are accurately accounted for.

Summary of Section 95152(i) Proposed Updates
Language was added to require reporting of flaring emissions for the natural gas distribution industry segment. Language was also added to require reporting of equipment and pipeline blowdown emissions.

Rationale for Section 95152(i) Proposed Updates
This provision is necessary to ensure the reporting of flares from the industry segments in this subarticle are accurately accounted for. The inclusion of equipment and pipeline blowdown emissions is necessary to provide a more complete picture of GHG emissions from this industry segment for the greenhouse gas inventory.

Summary of Sections 95153(a)-(b) Proposed Updates
The natural gas driven pneumatic device venting and natural gas pneumatic device venting sections from the 2010 version of the reporting regulation were modified to metered and non-metered natural gas pneumatic device venting. The equations in these sections were modified to reflect this change.

Rationale for Section 95153(a)-(b) Proposed Updates
These changes were needed to conform to the most up-to-date equations used to calculate emissions for these sources.

Summary of Section 95153(c) Proposed Updates
Equation 4 of Calculation Methodology 3 was changed to agree with the emissions calculation methodology adopted by the Western Climate Initiative (WCI) in their *Final Essential Requirements for Mandatory Reporting (Second Update),* (WCI, 2011). A term is included in order to correct volume measurements for the amount of H_2S present in gas entering and exiting the AGR unit.

Rationale for Section 95153(c) Proposed Updates
This change is necessary to provide for a more accurate emissions estimate.

Summary of Section 95153(d) Proposed Updates
Equation 5 in section 95153(d) was corrected by removing the conversion term 1,000cf/Mcf.

Rationale for Section 95153(d) Proposed Updates
This change is necessary to ensure an error was corrected in the regulation.

Summary of Section 95153(e) Proposed Updates
The equations used to calculate the well venting for liquids unloading was modified.

Rationale for Section 95153(e) Proposed Updates
These changes were needed to conform to the most up-to-date equations used to calculate emissions for these sources.

Summary of Section 95153(g) Proposed Updates
The title of this section was changed from "Blowdown Vent Stacks" to "Equipment and Pipeline Blowdowns" and text in 95153(h) was edited slightly to indicate that this method applies to pipelines as well as equipment. The equations were also modified to reflect the most up-to-date method.

Rationale for Section 95153(g) Proposed Updates
This change is needed to ensure this methodology includes all equipment blowdowns and blowdowns of pipelines. This change will provide a more accurate reflection of emissions occurring when equipment and pipes containing natural gas are vented to the atmosphere. The equation changes were needed to conform to the most up-to-date equations used to calculate emissions for these sources.

Summary of Section 95153(h) Proposed Updates
The calculation methods, except for the method describing unclosed gas-liquid separator liquid dump valves, were removed and replaced with the methods described in section 95153(v).

Rationale for Section 95153(h) Proposed Updates
This provision is necessary to ensure the reported emissions data is of sufficient quality for the cap-and-trade program. Additionally, the deleted methods prevented the potential for double counting of emissions.

Summary of Section 95153(j) Proposed Updates
An additional equation was added to clarify the calculation method for well testing, venting and flaring.

Rationale for Section 95153(j) Proposed Updates
The equation changes were needed to conform to the most up-to-date equations used to calculate emissions for these sources.

Summary of Section 95153(l) Proposed Updates
The original title of this section (Flare Stacks) was modified to read "Flare stack or other destruction device emissions." Section 95153(l)(1) was added to clarify that this method applies to all destruction equipment....flares, incinerators, oxidizers, and vapor combustion units," not just flares.

Rationale for Section 95153(l) Proposed Updates
This provision is necessary to ensure a more complete accounting of these emissions for greenhouse gas inventory purposes.

Summary of Section 95153(m) Proposed Updates
An additional equation was added to clarify the calculation method for centrifugal compressor venting.

Rationale for Section 95153(m) Proposed Updates
The equation changes were needed to conform to the most up-to-date equations used to calculate emissions for these sources.

Summary of Section 95153(n) Proposed Updates
An additional equation was added to clarify the calculation method for reciprocating compressor venting.

Rationale for Section 95153(n) Proposed Updates
The equation changes were needed to conform to the most up-to-date equations used to calculate emissions for these sources.

Summary of Section 95153(o) Proposed Updates
A requirement to use the leak detection and leaker emission factors method by the onshore petroleum and natural gas production industry segment was added. Changes were also made to the determination of the mole fraction of CH_4 and CO_2 in the GHG_i term in Equations 25 and 26.

Rationale for Section 95153(o) Proposed Updates
This provision is necessary to ensure an accurate measurement methodology is applied for leak detection and leaker emissions factors for the onshore petroleum and natural gas production industry segment. The modification to Equations 25 and 26 is necessary to allow for experimentally determined mole fractions of CH_4 and CO_2 in the

feed natural gas. The existing regulation only allows the use of default factors, which may lead to inaccuracies.

Summary of Section 95153(p) Proposed Updates
Changes were made to the determination of the mole fraction of CH_4 and CO_2 in the GHG_i term in Equation 27.

Rationale for Section 95153(p) Proposed Updates
The modification to Equation 27 is necessary to allow for experimentally determined mole fractions of CH_4 and CO_2 in the feed natural gas. The existing regulation only allows the use of default factors, which may lead to inaccuracies.

Summary of Section 95153(v) Proposed Updates
This section replaces the reporting requirements in 95153(h) for the onshore petroleum and natural gas production industry segment. Text was added to describe a flash liberation test or vapor recovery system method.

Rationale for Section 95153(v) Proposed Updates
This methodology is necessary to quantify emissions from GHGs CH_4 and CO_2 dissolved in crude oil and condensate which are emitted as the produced hydrocarbons acclimate to atmospheric pressure and are stored and moved from the production field to the refinery.

Summary of Section 95153(w) Proposed Updates
Language was added to this section to indicate that the vapor recovery system method may include emissions from crude oil condensate and produced water.

Rationale for Section 95153(w) Proposed Updates
This change is necessary to allow reporting entities who use this method to only perform one test to obtain the information required for section 95153(v) and (w).

Summary of Section 95153(y) Proposed Updates
An additional equation was added to clarify the calculation method for onshore petroleum and natural gas production and natural gas distribution combustion emissions.

Rationale for Section 95153(y) Proposed Updates
The equation changes were needed to conform to the most up-to-date equations used to calculate emissions for these sources.

Summary of Section 95154(f) Proposed Updates
The requirements for using best available monitoring methods (BAMM) were added. For the 2012 data year, BAMM will be accepted. Beginning for 2013 data, BAMM will no longer be an acceptable method.

Rationale for Section 95154(f) Proposed Updates
The provision is necessary to ensure the collection of accurate data for the cap-and-trade program beginning in 2013.

Summary of Section 95156 Proposed Updates
Modifications were made to this section to improve upon the allocation of allowances for petroleum and natural gas systems sector. Specific additions include: reporting requirements for cogeneration, steam and other sources located within the facility boundaries of an onshore petroleum and natural gas facility; adding reporting requirements for MMBtu of associated gas produced at thermal and other than thermal operations; adding the reporting of dry gas; adding product data reporting requirements for natural gas fractionators and natural gas processors; and adding voluntary reporting requirements for 2011 and 2012 data for associated gas, dry gas and operators of a natural gas liquid fractionating or processing facility.

Rationale for Section 95156 Proposed Updates
These provisions are necessary to support the cap-and-trade program, specifically the allocation of allowances process. The addition of the product data requirements from natural gas fractionators and processors is to reflect an omission from the previous regulation. Voluntary reporting of 2011 and 2012 product data for certain products may be necessary for reporting entities to receive their full allocation of allowances under the cap-and-trade program.

Summary of Section 95157 Proposed Updates
In order to maintain the order of subarticle 5, this section replaced the existing section 95157 (which moved to section 95158). The proposed section 95157 includes activity data that needs to accompany each emissions data report from this subarticle.

Rationale for Section 95157 Proposed Updates
This change is necessary to ensure reporters have a clear understanding of the activity data reporting requirements and to maintain as much congruency in the reporting order when compared to U.S. EPA.

Summary of Section 95157(a) Proposed Updates
This section explains which industry segments are subject to this section.

Rationale for Section 95157(a) Proposed Updates
This change is needed to ensure the correct industry segments report the correct supporting data.

Summary of Section 95157(b) Proposed Updates
This section explains the supporting requirements for offshore petroleum and natural gas production.

Rationale for Section 95157(b) Proposed Updates
This change is needed to ensure the correct supporting data is reported for offshore petroleum and natural gas production.

Summary of Section 95157(c) Proposed Updates
This section explains the reporting requirements for each of the other industry segments in subarticle 5.

Rationale for Section 95157(c) Proposed Updates
This section is necessary to ensure the correct supporting information to the emission calculations are reported correctly.

Summary of Section 95157(d) Proposed Updates
This section indicates that annual throughput must be reported for each industry segment.

Rationale for Section 95157(d) Proposed Updates
This provision is necessary to ensure the correct throughputs are reported.

Summary of Section 95157(e) Proposed Updates
This section requires onshore petroleum and natural gas production to report their best available estimates for certain parameters.

Rationale for Section 95157(e) Proposed Updates
The provision is necessary to ensure the reporting entity accurately reports the data required in this section.

Summary of Section 95158 Proposed Updates
This section was the former section 95157 in the 2010 reporting regulation. Other than the section name change, the language in this section did not change, except to no longer refer to the U.S. EPA rule.

Rationale for Section 95158 Proposed Updates
This provision is necessary to ensure that reporters clearly follow the reporting requirements. Aside from deleting the reference to the U.S. EPA rule, no changes were made to the language in the section.

Summary of Appendix A Proposed Updates
The appendix was added to ensure the correct emission factors for subarticle 5 were used. The tables represent the most up-to-date emission factors and were modified to include only emission factors relevant for the State of California.

Rationale for Appendix A Proposed Updates
The appendix is necessary to ensure reporters use the correct emission factors and report accurately.

B. Conforming Amendments to the Definition Section of the AB 32 Cost of Implementation Fee Regulation

Summary of Section 95202, Definitions.

This section defines all key terms used in the Fee Regulation that may not be in common use or which may potentially be ambiguous without a regulatory definition. Definitions have been edited, added, and in some cases, removed to conform to the definition amendments of the mandatory reporting regulation. These amendments clarify the meaning and intent of the regulation. These definition amendments do not alter any existing requirement under the Fee Regulation.

Rationale for Section 95102, Proposed Updates
This section is necessary to ensure that those subject to the Fee Regulation, the Cap-and-Trade Regulation, and the reporting regulation are able to understand and interpret the regulations consistently and correctly, and to avoid ambiguity and improve compliance with the regulations. Deletions, additions, and modifications from the current version of the Fee Regulation are necessary to ensure consistent interpretation of terms across all three regulations. These definition amendments do not alter any existing requirements under the Fee Regulation.

C. Conforming Amendments to the Definition Section of the Cap-and-Trade Regulation

Summary of Section 95802, Definitions.

This section defines all key terms used in the Cap-and-Trade Regulation that may not be in common use or which may potentially be ambiguous without a regulatory definition. Definitions have been edited, added, and in some cases, removed to conform to the definition amendments of the mandatory reporting regulation. These amendments clarify the meaning and intent of the regulation. These definition amendments do not alter any existing requirement under the Cap-and-Trade Regulation.

Rationale for Section 95802, Proposed Updates

This section is necessary to ensure that those subject to the Fee Regulation, the Cap-and-Trade Regulation, and the reporting regulation are able to understand and interpret the regulations consistently and correctly, and to avoid ambiguity and improve compliance with the regulations. Deletions, additions, and modifications from the current version of the Cap-and-Trade Regulation are necessary to ensure consistent interpretation of terms across all three regulations. These definition amendments do not alter any existing requirements under the Cap-and-Trade Regulation.

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ATTACHMENT A

PROPOSED REGULATION ORDER

NOTE: Changes to the regulation are shown in underline; deletions from the regulation are shown in ~~strikeout~~. "****" indicates that sections of regulation not printed are not changed.

PROPOSED AMENDMENTS TO THE REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

Amend Division 3, Chapter 1, Subchapter 10, Article 2, sections 95101, 95102, 95103, 95104, 95105, 95111, 95112, 95113, 95114, 95115, 95119, 95120, 95121, 95122, 95123, 95130, 95131, 95132, 95133, 95150, 95151, 95152, 95153, 95154, 95155, 95156, and 95157, title 17, California Code of Regulations; and add new section 95158, title 17, California Code of Regulations to read as follows:

Article 2: Mandatory Greenhouse Gas Emissions Reporting

Subarticle 1. General Requirements for Greenhouse Gas Reporting

***

§ 95101. Applicability.

(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: ~~categories included in Tables A-3 or A-4 of 40 CFR Part 98, and operators of facilities with emissions from stationary fuel combustion or geothermal electricity generation, subject to the limitations of this~~ :

1. Electricity generation units that report CO_2 mass emissions year round through 40 CFR Part 75~~Facilities with source categories in Table A-3 are subject to this article regardless of emissions level.~~;
2. Cement production~~Facilities with source categories in Table A-4 are subject to this article when stationary combustion emissions equal or exceed 10,000 metric tons CO_2e for 2012 or a later calendar year.~~;
3. Lime manufacturing~~Facilities with source categories in Table A-4 are also subject to this article when emissions from all applicable source categories in paragraph (b) of this equal or exceed 25,000 metric tons CO_2e, for 2011 or a later calendar year.~~;
4. Nitric acid production;
5. Petroleum refineries;

6. Geologic sequestration of carbon dioxide;
7. Injection of carbon dioxide.

(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 CO_2e for a calendar year:

1. Stationary fuel combustion, which includes electricity generating units not subject to 40 CFR Part 75;
2. Glass production;
3. Hydrogen production;
4. Iron and steel production;
5. Pulp and paper manufacturing;
6. Petroleum and natural gas systems;
7. Geothermal electricity generation.

(~~B~~C) Suppliers of fuels provided for consumption within California that are specified below in ~~subsection~~ paragraph (c);
(~~C~~D) Carbon dioxide suppliers as specified below in ~~subsection~~ paragraph (c), including CO_2 producers regardless of quantity produced, and CO_2 importers and exporters when bulk imports or exports equal or exceed 10,000 metric tons for 2011 or a later calendar year;
(~~D~~E) Electric power entities as specified below in ~~subsection~~ paragraph (d); and,
(~~E~~F) Operators of petroleum and natural gas systems as specified below in ~~subsection~~ paragraph (e).

***

(b) *Calculating GHG Emissions Relative to Thresholds.* For industrial facilities for which an emissions-based applicability threshold is specified in section 95101(a)(1)~~40 CFR §98.2~~, the operator must calculate emissions for comparison to applicable thresholds using the requirements of 40 CFR §98.2(b)-(c), except as specified below~~.~~:

(1) For the purpose of computing emissions relative to the 25,000 metric ton CO_2e threshold specified in section 95812 of the cap-and-trade regulation, operators must include all covered emissions.
(2) For the purpose of computing emissions relative to the 10,000 metric ton CO_2e threshold for reporting applicability, operators must include emissions of CO_2, CH_4 and N_2O from stationary combustion sources and process emissions, but may exclude ~~process,~~ vented~~,~~ and fugitive emissions from the estimate.

***

(c) *Fuel and Carbon Dioxide Suppliers.* The suppliers listed below, as defined in section 95102(a), are required to report under this article when they produce, import and/or deliver an annual quantity of fuel that, if completely combusted, oxidized, or used in other processes, would result in the release of greater than or equal to 10,000 metric tons of CO_2e in California, unless otherwise specified in this article:

***

(5) California consignees of liquefied petroleum gas, compressed natural gas, or liquefied natural gas, as described in section 95122;

***

(e) *Petroleum and Natural Gas Systems.* The facility types listed below, as further specified in section 95150, are required to report under this article when their stationary combustion and process emissions equal or exceed 10,000 metric tons of CO_2e, or their stationary combustion, process, fugitive, and vented emissions equal or exceed 25,000 metric tons of CO_2e.

(1) Offshore petroleum and natural gas production facilities;
(2) Onshore petroleum and natural gas production facilities~~, as defined in section 95102~~;

***

(h) *Cessation of Reporting.* ~~Except as otherwise specified below, a~~A facility operator or supplier whose emissions fall below the applicable emissions reporting thresholds of this article and who wishes to cease annual reporting must comply with ~~40 CFR §98.2(i)~~ the requirements specified in this paragraph. The operator or supplier must provide the letter notifications specified below ~~in 40 CFR §98.2(i)~~ to the address indicated in section 95103 of this article. ~~For purposes of this article:~~

(1) ~~Wherever 40 CFR §98.2(i)(1) states "25,000 metric tons of CO_2e per year," the phrase "10,000 metric tons of CO_2e per year" shall be substituted, and reporting shall be required for three years rather than five years.~~ For facilities with source categories in section 95101(a)(1)(A) that are subject to the requirements of this article regardless of emissions level, cessation of reporting provisions in section 95101(h)(1) apply, but the 2011 data year is the earliest year that criteria for cessation can be applied.

If reported emissions are less than 10,000 metric tons of CO_2e per year for three consecutive years, then the owner, operator, or supplier may discontinue complying with this article provided that the owner, operator, or supplier submits a notification to ARB that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification must be submitted no later than March 31 of the year immediately following the third consecutive year in which emissions are less than 10,000 metric tons of CO_2e per year. The owner, operator, or supplier must maintain the corresponding records required under section 95103 for each of the five consecutive years and retain such records for five years following the year that reporting was discontinued. The owner, operator, or supplier must resume reporting if annual emissions in any future calendar year increase to 10,000 metric tons of CO_2e per year or more.

(2) ~~In cases of permanent shutdown as specified in 40 CFR §98.2(i)(3), a reporter must submit an emissions data report for the year in which a facility or supplier's GHG emitting processes and operations ceased to operate, and for the first full year of non-operation that follows.~~ If the operations of a facility or supplier are changed such that all applicable GHG-emitting processes and operations listed in paragraph (a)(1) of this section cease to operate or are permanently shut down, the owner, operator, or supplier must submit an emissions data report for the year in which a facility or supplier's GHG-emitting processes and operations ceased to operate, and for the first full year of non-operation that follows. The owner, operator, or supplier must submit a notification to ARB that announces the cessation of reporting and certifies to the closure of all GHG-emitting processes and operations no later than March 31 of the year following such changes. Paragraph 95101(h)(2) does not apply to seasonal or other temporary cessation of operations. The owner, operator, or supplier must resume reporting for any future calendar year during which any of the GHG-emitting processes or operations resume operation and are subject to reporting pursuant to section 95101(a)(1).

***

(4) Electric power entities must comply with the following requirements for cessation of reporting:

(A) Electric power entities that import or export electricity in 2011 or 2012 must continue to submit, certify, and verify an emissions data report through the 2014 data year, the end of the first compliance period. If an electric power entity has zero imports or exports, it must indicate as such in its emissions data report.

(B) Electric power entities that import or export electricity in any year of a subsequent compliance period must continue to submit, certify, and verify an emissions data report through the end of the same compliance period. If an electric power entity has zero imports or exports, it must indicate as such in its emissions data report.

(C) Electric power entities no longer importing or exporting electricity at the beginning of a subsequent compliance period are not required to submit, certify, and verify an emissions data report demonstrating that they have no imports or exports pursuant to this article, but must notify the Executive Officer in writing of the reason(s) for cessation of reporting. The notification must be submitted no later than March 31 of the year following the last year that the electric power entity is required to submit an emissions data report.

(D) Electric power entities who meet the definition of "retail provider" must always report retail sales for each calendar year. WAPA and DWR must always report pump loads for each calendar year.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95102. Definitions.

(a) For the purposes of this article, the following definitions shall apply:

(1) "Absorbent circulation pump" means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

*** [no changes were made except to renumber]

(~~9~~10) "Air dried ton of paper" means paper with ~~6%~~ percent moisture content.

(11) "Air injected flare" means a flare in which air is blown into the base of a flare stack to induce complete combustion of gas.

*** [no changes were made except to renumber]

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

*** [no changes were made except to renumber]

(~~19~~21) "Associated gas" or "produced gas" means a natural gas that is produced ~~from gas wells or gas produced~~ in association with the production of crude oil.

*** [no changes were made except to renumber]

(42) "Boiler" means a closed vessel or arrangement of vessels and tubes, together with a furnace or other heat source, in which water is heated to produce hot water or steam.

*** [no changes were made except to renumber]

(51) "Butylene" or "n-Butylene" means an olefinic straight-chain hydrocarbon with molecular formula C_4H_8.

*** [no changes were made except to renumber]

(55) "Calcined coke" means petroleum coke purified to a dry, pure form of carbon suitable for use as anode and other non-fuel applications.

*** [no changes were made except to renumber]

(58) "Calibrated bag" means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to an emitting source such that the emissions inflate the bag to its calibrated volume.

*** [no changes were made except to renumber]

(~~71~~67) "Carbon dioxide weighted tonne" or "CO_2 weighted tonne" or "CWT" means a metric created to evaluate the greenhouse gas efficiency of petroleum refineries and related processes, stated in units of metric tons. The CWT 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 CWT 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 CWT factor is expressed as a value weighted relative to crude distillation.

*** [no changes were made except to renumber]

(71) "CBOB-summer" or "conventional blendstock for oxygenate blending-summer" means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of conventional-summer.

(72) "CBOB-winter" or "conventional blendstock for oxygenate blending-winter" means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of conventional-winter.

*** [no changes were made except to renumber]

(76) "Centrifugal compressor dry seals" mean a series of rings around the compressor shaft where it exits the compressor case that operate mechanically under the opposing forces to prevent natural gas or CO_2 from escaping to the atmosphere.

(77) "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 CO_2. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor seals.

*** [no changes were made except to renumber]

(~~74~~84) "Cogeneration" means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy. Cogeneration must involve generation of electricity and useful thermal energy and some form of waste heat recovery. Some examples of cogeneration include: (a) a gas turbine or reciprocating engine generating electricity by combusting fuel, which then uses a heat recovery unit to capture useful heat from the exhaust stream of the turbine or engine; (b) Steam turbines generating electricity as a byproduct of steam generation through a fired boiler; (c) Cogeneration systems in which the fuel input is first applied to a thermal process such as a furnace and at least some of the heat rejected from the process is then used for power production. For the purposes of this article, a combined-cycle power generation unit, where ~~all of the generated steam is used for electricity generation~~ none of the generated thermal energy is used for industrial, commercial, or heating and cooling purposes (these purposes exclude any thermal energy utilization that is either in support of or a part of the electricity generation system), is not considered a cogeneration unit.

*** [no changes were made except to renumber]

(98) "Compressed natural gas" or "CNG" means natural gas in high-pressure containers that is highly compressed (though not to the point of liquefaction), typically to pressures ranging from 2900 to 3600 psi.

*** [no changes were made except to renumber]

(~~93~~104) "Continuous bleed" means a continuous flow of pneumatic supply natural gas to the process ~~measurement~~control device (e.g. level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

*** [no changes were made except to renumber]

(106) "Continuous physical transmission path" means the full transmission path shown in the physical path table of a single NERC e-tag from the first point of receipt closest to the generation source to the final point of delivery closest to the final sink. This is one criterion to establish direct delivery.

(107) "Conventional-summer" means finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR §80.40, but which meet summer RVP standards required under 40 CFR §80.27 or as specified by the state. Note: This category excludes conventional gasoline for oxygenate blending (CBOB) as well as other blendstock.

(108) "Conventional-winter" means finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR §80.40 or the summer RVP standards required under 40 CFR §80.27 or as specified by the state. Note: This category excludes conventional blendstock for oxygenate blending (CBOB) as well as other blendstock.

*** [no changes were made except to renumber]

(111) "Covered product data" means all product data included in the allocation of allowances under sections 95870, 95890, and 95891 of the cap-and-trade regulation, regardless of whether the cap-and-trade regulation imposes a compliance obligation for the data year.

*** [no changes were made except to renumber]

(118) "Dehydrator vent emissions" means natural gas and CO_2 release from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator to the atmosphere or a flare, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

(~~103~~119) "Delayed coking" means a process by which heavier crude oil fractions are thermally decomposed under conditions of elevated temperature and pressure to produce a mixture of lighter oils and petroleum coke.

*** [no changes were made except to renumber]

(121) "Demethanizer" means the natural gas processing unit that separates methane rich residue gas from the heavier hydrocarbons (e.g., ethane, propane, butane, pentane-plus) in the feed natural gas stream.

*** [no changes were made except to renumber]

(~~108~~125) "Direct delivery of electricity" or "directly delivered" means electricity that meets any of the following criteria:

(A) The facility has a first point of interconnection with a California balancing authority;

(B) The facility has a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area;

(C) The electricity 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~~final point of delivery~~ located in the state of California; or

(D) There is an agreement to dynamically transfer electricity from the facility to a California balancing authority.

*** [no changes were made except to renumber]

(130) "Distribution pipeline" means a pipeline that is designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA) in 49 CFR §192.3.

*** [no changes were made except to renumber]

(136) "Electric Power Entity" or "EPE" means those entities specified in section 95101(d) of this article, including electricity importers and exporters; retail providers, including multi-jurisdictional retail providers; the California Department of Water Resources (DWR); the Western Area Power Administration (WAPA); and the Bonneville Power Administration (BPA).

*** [no changes were made except to renumber]

(~~118~~137) "Electricity exporter" means electric power entities~~marketers and retail providers~~ that deliver exported electricity. ~~For electricity delivered between balancing authority areas, t~~The entity that exports electricity is identified on the NERC e-Tag as the purchasing-selling entity (PSE) on the last segment of the tag's physical path, with the point of receipt located inside the state of California and the point of delivery located outside the state of California.

(~~121~~140) "Electricity importers" ~~are marketers and retail providers that~~ deliver imported electricity. For electricity that is scheduled with a NERC e-Tag to a final point of delivery inside the state of California~~delivered between balancing authority areas~~, the electricity importer is identified on the NERC e-Tag as the purchasing-selling entity (PSE) on the last segment of the tag's physical path with the point of receipt located outside the state of California and the point of delivery located inside the state of California. For facilities physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission and distribution system when the electricity is not scheduled on a NERC e-Tag, the importer is the facility operator or scheduling coordinator. Federal and state agencies are subject to the regulatory authority of ARB under this article and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and California Department of Water Resources (DWR).

*** [no changes were made except to renumber]

(~~128~~147) "Emissions data verification statement" means the final statement rendered by a verification body attesting whether a reporting entity's covered emissions data in their emissions data report is free of material misstatement, and whether the emissions data conforms to the requirements of this article.

*** [no changes were made except to renumber]

(~~133~~152) "Enterer" means an entity that imports into California motor vehicle fuel, diesel fuel, fuel ethanol, biodiesel, non-exempt biomass-derived fuel or renewable fuel and who is the importer of record under federal customs law or the owner of fuel upon import into California if the fuel is not subject to federal customs law. Only enterers that import the fuels specified in this definition outside the bulk transfer/terminal system are subject to reporting under the regulation.

*** [no changes were made except to renumber]

(~~137~~156) "Equipment leak detection" means the process of identifying emissions from equipment, components, and other point sources.

*** [no changes were made except to renumber]

(158) "Ethanol" is an anhydrous alcohol with molecular formula C_2H_5OH.

(159) "Ethylene" is an olefinic hydrocarbon with molecular formula C_2H_4.

*** [no changes were made except to renumber]

(~~144~~165) "Facility," unless otherwise specified in relation to natural gas distribution facilities and onshore petroleum and natural gas production facilities as defined in section 95102(a), means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of -way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

(166) "Facility," with respect to natural gas distribution for the purposes of sections 95150 to 95158 of this article, means the collection of all

distribution pipelines and metering-regulating stations that are operated by a local distribution company (LDC) within the State of California that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

(167) "Facility," with respect to onshore petroleum and natural gas production for the purposes of sections 95150 to 95158 of this article, means all petroleum and natural gas equipment on a well-pad or associated with a well pad 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 and that are located in a single hydrocarbon basin as defined in section 95102(a). Where a person or 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.

(168) "Farm taps" are pressure regulation stations that deliver gas directly from transmission pipelines to rural customers. In some cases a nearby LDC may handle the billing of the gas to the customer(s).

*** [no changes were made except to renumber]

(~~147~~171) "Field," in the context of oil and gas systems, means oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List 2008, DOE/EIA 0370(08), January 2009, which is hereby incorporated by reference.

(172) "Field accuracy assessment" means a test, check, or engineering analysis intended to confirm that a flow meter or other mass or volume measurement device is operating within an acceptable accuracy range. A field accuracy assessment should be conducted in a manner that does not interrupt operations or require removal of the meter or require primary element inspection, if possible. The selected method for field accuracy assessment will vary based on meter type and piping system design, and may be performed by the facility operator, a third party meter servicing firm, or the original equipment manufacturer.

(173) "Final point of delivery" means the sink specified on the NERC e-Tag, where defined points have been established through the NERC Registry. When NERC e-Tags are not used to document electricity deliveries, as may be the case within a balancing authority, the final point of delivery is the location of the load. Exported electricity is disaggregated by the final point of delivery on the NERC e-Tag.

(174) "First deliverer of electricity" or "first deliverer" means the owner or operator of an electricity generating facility in California or an electricity importer.

(175) "First point of delivery in California" means the first defined point on the transmission system located inside California at which imported electricity and electricity wheeled through California may be measured, consistent with defined points that have been established through the NERC Registry.

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

*** [no changes were made except to renumber]

(~~150~~179) "Flare combustion efficiency" means the fraction of ~~hydrocarbon gas~~liquid and gases sent to the flare, on a volume or mole basis, that is combusted at the flare burner tip.

(~~151~~180) "Flare stack emissions" means CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in the flare~~s~~.

*** [no changes were made except to renumber]

(183) "Flow meter" means a measurement device consisting of one or more individual components that is designed to measure the bulk fluid movement of liquid or gas through a piped system at a designated point. Bulk fluid movement can be measured with a variety of devices in units of mass flow or volume.

*** [no changes were made except to renumber]

(188) "Forced extraction of natural gas liquids" means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself, natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperatures, or the condensation of water or

hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids.

*** [no changes were made except to renumber]

(204) "Fugitive equipment leak" means the unintended or incidental emissions of greenhouse gases from the production, transmission, processing, storage, use or transportation of fossil fuels, greenhouse gases, or other equipment.

*** [no changes were made except to renumber]

(209) "Gas conditions" means the actual temperature, volume, and pressure of a gas sample.

*** [no changes were made except to renumber]

(211) "Gas to oil ratio" or "GOR" means the ratio of gas produced from a barrel of crude oil or condensate when cooling and depressurizing these liquids to standard conditions, expressed in terms of standard cubic feet of gas per barrel of oil.

*** [no changes were made except to renumber]

(~~182~~216) "Generation providing entity" or "GPE" means a ~~merchant selling energy from owned, affiliated, or contractually bound generation. F~~for purposes ~~of reporting delivered electricity pursuant to section 95111, a GPE is the PSE, operator, or scheduling coordinator with prevailing rights to claim electricity from a specified source. A~~ facility or generating unit operator, full or partial owner, party to a contract for a fixed percentage of net generation, sole party to a tolling agreement with the owner, or exclusive marketer ~~is~~ recognized by ARB ~~as a generation providing entity~~ that is either the electricity importer or exporter with prevailing rights to claim electricity from the specified source.

*** [no changes were made except to renumber]

(231) "High-bleed pneumatic devices" means automatic, continuous or intermittent bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously or intermittently (bleeds) to the atmosphere at a rate in excess of 6 standard cubic feet per hour.

*** [no changes were made except to renumber]

(233) "Horizontal well" means a well bore that has a planned deviation from primarily vertical to primarily horizontal inclination or declination tracking in parallel with and through the target formation.

*** [no changes were made except to renumber]

(246) "Intermittent bleed pneumatic devices" means automated flow control devices powered by pressurized natural gas and used for automatically maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge all or a portion of the full volume of the actuator intermittently when control action is necessary, but do not bleed continuously. Intermittent bleed devices which bleed at a cumulative rate of 6 standard cubic feet per hour or greater are considered high bleed devices for the purposes of this regulation.

(~~210~~247) "Internal combustion" means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and high–pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

*** [no changes were made except to renumber]

(252) "Isobutane" is a paraffinic branch chain hydrocarbon with molecular formula C_4H_{10}.

(253) "Isobutylene" is an olefinic branch chain hydrocarbon with molecular formula C_4H_8.

(254) "Isopentane" is the methylbutane or 2-methylbutane, branched chain, isomer of C_5H_{12} under the International Union of Pure and Applied Chemistry (IUPAC) nomenclature.

*** [no changes were made except to renumber]

(260) "Last point of delivery in California" means the last defined point on the transmission system located inside California at which exported electricity may be measured, consistent with defined points that have been established through the NERC Registry.

*** [no changes were made except to renumber]

(~~221~~262) "Lead verifier independent reviewer" or "independent reviewer" means a lead verifier within a verification body who has not participated in conducting verification services for a reporting entity, offset project developer, or authorized project designee for the current reporting year who provides an independent review of verification services rendered to the reporting entity as required in section 95131. The independent reviewer is not required to meet the requirements for a sector specific verifier.

*** [no changes were made except to renumber]

~~(224) "Liquefied hydrogen" means hydrogen in a liquid state.~~

*** [no changes were made except to renumber]

(~~226~~266) "Liquefied petroleum gas" or "LP-Gas" or "LPG" means a flammable mixture of hydrocarbon gases used as a fuel. LPG is a natural gas liquid (NGL) that is primarily a mixture~~s~~ of propane~~,~~ and butane, with small amounts of propene (propylene) and ethane. The most common specification categories are propane grades HD-5, HD-10, and commercial grade propane, and propane/butane mix. LPG also includes both odorized and non-odorized liquid petroleum gas, and is also referred to as propane.

(267) "Liquid hydrogen" means hydrogen in a liquid state.

*** [no changes were made except to renumber]

(273) "Low-bleed pneumatic devices" means automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously or intermittently bleeds to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

*** [no changes were made except to renumber]

(~~235~~277) "Material misstatement" means any discrepancy, omission, or misreporting, or aggregation of the three, identified in the course of verification services that leads a verification team to believe that- the total reported ~~GHG~~covered emissions (metric tons of CO_2e) or ~~a-~~ total reported ~~single~~ covered product data ~~component~~ contains errors greater than 5%, as applicable, in an emissions data report-. Material misstatement is calculated separately for covered emissions and covered product data, ~~for each type of data~~ as specified in section 95131(b)(12)(A).

*** [no changes were made except to renumber]

(280) “Meter/regulator run” means a series of components used in regulating pressure or metering natural gas flow or both.

(281) “Metering/regulating station” means a station that meters the flowrate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.

*** [no changes were made except to renumber]

(284) “Midgrade gasoline” means gasoline that has an octane rating greater than or equal to 88 and less than or equal to 90. This definition applies to the midgrade categories of conventional-summer, conventional-winter, reformulated-summer, and reformulated-winter. For midgrade categories of RBOB-summer, RBOB-winter, CBOB-summer, and CBOB-winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

*** [no changes were made except to renumber]

(~~251~~296) “Natural gas” means a naturally occurring mixture or process derivative 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 field quality (which varies widely) or pipeline quality. 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.

*** [no changes were made except to renumber]

(~~254~~299) “Natural gas liquids” or “NGLs~~-~~” ~~“~~means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline), and high (liquefied petroleum gas) vapor pressure. Generally, such liquids consist of ethane, propane, butanes, ~~and~~ pentanes ~~plus~~, and higher molecular weight hydrocarbons. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

*** [no changes were made except to renumber]

(301) “Natural gasoline” means a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas. It includes isopentane. Natural gasoline is a natural gas liquid of intermediate vapor pressure.

*** [no changes were made except to renumber]

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

*** [no changes were made except to renumber]

(316) "Offset project specific verifier" means an individual who has been accredited by ARB to verify offset projects of a specific offset project type.

*** [no changes were made except to renumber]

(319) "Oil and gas systems specialist" means a verifier accredited to meet the requirements of section 95131(a)(2) for providing verification services to operators petroleum refineries, hydrogen production units or facilities, and petroleum and natural gas systems listed in section 95101(e).

*** [no changes were made except to renumber]

(~~274~~322) "Onshore petroleum and natural gas production owner or operator" means the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued, which operates an onshore petroleum and/or natural gas production facility (as described in section 95102(a) ~~40 CFR §98.230(a)(2)~~). Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the State or Federal business income taxes is considered the owner or operator.

*** [no changes were made except to renumber]

(329) "Pentane" is the n-pentane, straight chain, isomer of C_5H_{12} under the International Union of Pure and Applied Chemistry (IUPAC) nomenclature.

(330) "Pentanes plus" or "C5+" means a mixture of hydrocarbons that is a liquid at ambient temperature and pressure, and consists mostly of pentanes (five carbon chain) and higher carbon number hydrocarbons. Pentanes plus includes normal pentane, isopentane, hexanes-plus (natural gasoline), and plant condensate.

*** [no changes were made except to renumber]

(~~282~~332) "Performance review" means an assessment conducted by ARB of an applicant seeking to become accredited as a verification body, verifier, lead verifier, offset project specific verifier, or sector specific verifier pursuant to section 95132 of this article. Such an assessment may include a review of applicable past sampling plans, verification reports, verification statements, conflict of interest submittals, and additional information or documentation regarding the applicant's fitness for qualification.

*** [no changes were made except to renumber]

(~~291~~341) "Point of delivery" or "POD" means the point on an electricity transmission or distribution system where a deliverer makes electricity available to a receiver, or available to serve load. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system, or a distribution substation where electricity is imported into California over a multi-jurisdictional retail provider's distribution system.

(~~292~~342) "Point of receipt" or "POR" means the point on an electricity transmission or distribution system where an electricity receiver receives electricity from a deliverer. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

*** [no changes were made except to renumber]

(~~296~~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.

(~~297~~347) "Positive emissions data verification statement" means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered emissions data in the submitted emissions data report is free of material misstatement and that the emissions data conforms to the requirements of this article.

(~~298~~348) "Positive product data verification statement" means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered product data in the submitted emissions data report is free of material misstatement and that the product data conforms to the requirements of this article.

*** [no changes were made except to renumber]

(~~301~~351) "Power contract" or "written power contract," as used for the purposes of documenting specified versus unspecified sources of imported and exported electricity, means 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, and tariff provisions, without regard to duration, or written agreements to import on behalf of another entity, as long as that other entity also reports to ARB the same imported or exported electricity.

(352) "Premium grade gasoline" is gasoline having an antiknock index, i.e., octane rating, greater than 90. This definition applies to the premium grade categories of conventional-summer, conventional-winter, reformulated-summer, and reformulated-winter. For premium grade categories of RBOB-summer, RBOB-winter, CBOB-summer, and CBOB-winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

*** [no changes were made except to renumber]

(~~303~~354) "Primary refinery products" means aviation gasoline, motor gasoline (finished), kerosene-type jet fuel, distillate fuel oil, renewable liquid fuels, and-asphalt. For the purpose of calculating this value for each refinery ARB will convert blendstocks into their finished fuel volumes by multiplying blendstocks by an assumed blending ratio.

*** [no changes were made except to renumber]

(359) "Process Heater" means equipment for the heating of process streams (gases, liquids, or solids) other than water through heat provided by fuel combustion.

(360) "Process emissions specialist" means a verifier accredited to meet the requirements of section 95131(a)(2) for providing verification services to operators of facilities engaged in cement production, glass production, lime manufacturing, pulp and paper manufacturing, iron and steel production, and nitric acid production.

*** [no changes were made except to renumber]

(~~312~~365) "Product data verification statement" means the final statement rendered by a verification body attesting whether a reporting entity's covered product data in their emissions data report is free of material misstatement, and whether the product data conforms to the requirements of this article.

*** [no changes were made except to renumber]

(369) "Propylene" is an olefinic hydrocarbon with molecular formula C_3H_6.

*** [no changes were made except to renumber]

(~~326~~380) "Qualified positive emissions data verification statement" means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered emissions data in the submitted emissions data report is free of material misstatement and is in conformance with section 95131(b)(9), but the emissions data may include one or more other nonconformances with the requirements of this article which do not result in a material misstatement.

(~~327~~381) "Qualified positive product data verification statement" means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered product data in the submitted emissions data report is free of material misstatement and is in conformance with section 95131(b)(9), but the product data may include one or more other nonconformance(s) with the requirements of this article which do not result in a material misstatement.

(~~328~~382) "Qualified positive verification statement" means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the submitted emissions data report is free of material misstatement and is in conformance with section 95131(b)(9), but the emissions data report may include one or more other nonconformance(s) with the requirements of this article which do not result in a material misstatement. This definition applies to the qualified positive emissions data verification statement and the qualified positive product data verification statement.

*** [no changes were made except to renumber]

(385) "RBOB-summer" or "reformulated blendstock for oxygenate blending-summer" means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of reformulated-summer.

(386) "RBOB-winter" or "reformulated blendstock for oxygenate blending-winter" means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of reformulated-winter.

*** [no changes were made except to renumber]

(390) "Reciprocating internal combustion engine" or "RICE" or "piston engine" means an engine that uses heat from the internal combustion of fuel to create pressure that drives one or more reciprocating pistons, creating mechanical energy.

(391) "Re-condenser" means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

*** [no changes were made except to renumber]

(398) "Reformulated-summer" means finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR §80.40 and 40 CFR §80.41, and summer RVP standards required under 40 CFR §80.27 or as specified by the state. Reformulated gasoline excludes RBOB as well as other blendstock.

(399) "Reformulated-winter" means finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR §80.40 and 40 CFR §80.41, but which do not meet summer RVP standards required under 40 CFR §80.27 or as specified by the state. Note: This category includes Oxygenated Fuels Program Reformulated Gasoline (OPRG). Reformulated gasoline excludes RBOB as well as other blendstock.

(400) "Regular grade gasoline" is gasoline having an antiknock index, i.e., octane rating, greater than or equal to 85 and less than 88. This definition applies to the regular grade categories of conventional-summer, conventional-winter, reformulated-summer, and reformulated-winter. For regular grade categories of RBOB-summer, RBOB-winter, CBOB-summer, and CBOB-winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

*** [no changes were made except to renumber]

(402) "Rendered animal fat" or "tallow" means fats extracted from animals which are generally used as a feedstock in making biodiesel.

(405) "Renewable Energy Credit" or "REC" has the same meaning as ascribed to the cap-and-trade regulation section 95802(a).

*** [no changes were made except to renumber]

(416) "Sales oil" means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer tank gauge.

*** [no changes were made except to renumber]

(418) "Sector specific verifier" means a verifier accredited pursuant to section 95132(b)(5)(A) as one or more of the following types of specialists defined pursuant to this section: a transactions specialist, an oil and gas systems specialist, or a process emissions specialist.

*** [no changes were made except to renumber]

(~~358~~) ~~"Single product data component" means each individual annual product data item that is required to be reported pursuant to the product data requirements of this article.~~

(423) "Sink" or "sink to load" or "load sink" means the sink identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Exported electricity is disaggregated by the sink on the NERC e-Tag, also referred to as the final point of delivery on the NERC e-Tag.

*** [no changes were made except to renumber]

(427) "Sour natural gas" means natural gas that contains significant concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

*** [no changes were made except to renumber]

(430) "Source of generation" or "generation source" means the generation source identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Imported electricity and wheels are disaggregated by the source on the NERC e-Tag, also referred to as the first point of receipt.

*** [no changes were made except to renumber]

(437) "Steam generator" means equipment that produces steam using an external heat source.

*** [no changes were made except to renumber]

(445) "Sweet gas" means natural gas with low concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

*** [no changes were made except to renumber]

(~~391~~460) "Total thermal output" means the total amount of usable thermal energy generated by a cogeneration or bigeneration unit that can potentially be made available for use in any industrial or commercial processes, heating or cooling applications, or delivered to other end users. This quantity excludes the heat content of returned condensate and makeup water, but includes the thermal energy used for supporting (but not directly used for) power generation, thermal energy used in other on-site processes or applications that are not in support of or a part of the electricity generation system, thermal energy provided or sold to particular end-user, and thermal energy that is otherwise not utilized. Thermal energy directly used for power generation (e.g., steam used to drive a steam turbine generator for electricity generation) is not included in total thermal output.

(461) "Transactions specialist" means a verifier accredited to meet the requirements of section 95131(a)(2) for providing verification services to electric power entities; suppliers of petroleum products and biofuels; suppliers of natural gas, natural gas liquids, and liquefied petroleum gas; and suppliers of carbon dioxide.

(462) "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).

(~~392~~463) "Transmission pipeline" means a high pressure cross country pipeline transporting ~~sellable~~saleable quality natural gas from production or natural gas from processing to natural gas distribution pressure let-down, metering, regulating stations, where the natural gas is typically odorized before delivery to customers.

*** [no changes were made except to renumber]

(465) "Turbine" means any of various types of machines in which the kinetic energy of a moving fluid is converted into mechanical energy by causing a bladed rotor to rotate.

*** [no changes were made except to renumber]

(~~399~~471) "Unspecified source of electricity" or "unspecified source" means a source of electricity that is not a specified source at the time of entry into the transaction to procure the electricity. ~~procured and delivered without limitation at the time of transaction to a specific facility's or unit's generation. Unspecified sources contribute to the bulk system power pool and typically are dispatchable, marginal resources that do not serve baseload~~.

*** [no changes were made except to renumber]

(476) "Vapor recovery system" means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed

of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

(477) "Vegetable oil" means oils extracted from vegetation that are generally used as a feedstock in making biodiesel.

*** [no changes were made except to renumber]

(487) "Vertical well" means a well bore that is primarily vertical but has some unintentional deviation to enter one or more subsurface targets that are off-set horizontally from the surface location, intercepting the targets either vertically or at an angle.

*** [no changes were made except to renumber]

(491) "Well testing venting and flaring" means venting and/or flaring of natural gas at the time the production rate of a well is determined for regulatory, commercial, or technical purposes. If well testing is conducted immediately after a well completion or workover, then it is considered part of well completion or workover.

*** [no changes were made except to renumber]

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

§ 95103. Greenhouse Gas Reporting Requirements.

The facilities, suppliers, and entities specified in section 95101 must monitor emissions and submit emissions data reports to the Air Resources Board following the requirements specified in 40 CFR §98.3 and §98.4, except as otherwise provided in this part.

(a) *Abbreviated Reporting for Facilities with Emissions Below 25,000 Metric Tons of CO_2e.* A facility operator may submit an abbreviated emissions data report under this article if all of the following conditions have been met: the facility operator does not have a compliance obligation under the cap-and-trade regulation during any year of the current compliance period; the operator is not subject to the reporting requirements of 40 CFR Part 98; and the facility total stationary combustion, process, fugitives and venting emissions are below 25,000 metric tons of CO_2e in 2011 and each subsequent year. This provision does not apply to suppliers or electric power entities. Abbreviated reports must include the information in paragraphs (1)-(~~6~~7) below, and comply with the requirements specified in paragraphs (~~7~~8)-(11~~0~~) below:

***

(3) Total facility GHG process emissions aggregated for all process emissions sources and calculated according to the requirements in the following parts, expressed in metric tons of total CO_2, CO_2 from biomass-derived fuels, CH_4, and N_2O, as applicable:

(A) 40 CFR §98.143 for glass production;
(B) 40 CFR §98.163 for hydrogen production;
(C) 40 CFR §98.173 for iron and steel production;
(D) 40 CFR §98.273 for pulp and paper manufacturing;
(E) Subarticle 5 of this article for petroleum and natural gas systems.

(4~~3~~) Identification of the methods chosen for determining emissions.

(5~~4~~) Any facility operating data or process information used for the GHG emission calculations, including fuel use by fuel type, reported in million standard cubic feet for gaseous fuels, gallons for liquid fuels, short tons for solid fuels, and bone-dry short tons for biomass-derived solid fuels. If applicable, include high heat values and carbon content values used to calculate emissions. Missing fuel use or fuel characteristics data must be substituted according to the requirements of 40 CFR §98.35.

(6~~5~~) For facilities with on-site electricity generation or cogeneration, the applicable information specified in sections 95112(a)-(b) of this article. Geothermal facilities must also report the information specified in section 95112(e).

(7~~6~~) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of 40 CFR §98.4(e)(1).

(8~~7~~) Abbreviated emissions data reports submitted under this provision must be certified as complete and accurate no later than June 1 of each calendar year. This requirement begins in 2012 for facilities who were required to report GHG emissions to ARB in 2011, and begins in 2013 for facilities not previously reporting to ARB.

(9~~8~~) Subsequent revisions according to the requirements of 40 CFR §98.3(h) must be submitted only if cumulative errors are found to exceed 5 percent of total CO~~2~~$_2$e emissions, or if error correction would cause the emissions total to exceed 25,000 metric tons of CO~~2~~$_2$e, in which case a report that meets the full requirements of this article must be submitted within ninety days of discovery.

(10~~9~~) ~~—~~For abbreviated reports submitted under this provision, records must be kept according to the requirements of 40 CFR §98.3(g), except that a written GHG Monitoring Plan is not required.

(11~~0~~) ~~—~~An abbreviated emissions data report is not subject to the third-party verification requirements of this article.

***

(f) *Verification Requirement and Deadlines.* The requirements of this paragraph apply to each reporting entity submitting an emissions data report for the previous calendar year that indicates emissions equaled or exceeded 25,000 metric tons of CO_2e, including CO_2 from biomass-derived fuels and geothermal sources, or each reporting entity that has or has had a compliance obligation under the cap-and-trade regulation in any year of the current compliance period. The reporting entity subject to verification must obtain third-party verification services for that report from a verification body that meets the requirements specified in Subarticle 4 of this article. Such services must be completed and separate verification statements for emissions data and for product data, as applicable, must be submitted by the verification body to the Executive Officer by September 1 each year. Each reporting entity must ensure that these verification statements are submitted by this deadline. Contracting with a verification body without providing sufficient time to complete the verification statements by the applicable deadline will not excuse the reporting entity from this responsibility. These requirements are additional to the requirements in 40 CFR §98.3(f).

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(j) *Calculating, Reporting, and Verifying Emissions from Biomass-Derived Fuels.* The operator or supplier must separately identify and report all biomass-derived fuels as described in section 95852.2(a) of the cap-and-trade regulation. Except for operators that use the methods of 40 CFR §98.33(a)(2)(iii) or §98.33(a)(4), the operator or supplier must separately identify, calculate, and report all direct emissions of CO_2 resulting from the combustion of biomass-derived fuels as specified in sections 95112 and 95115 for facilities, and sections 95121 and 95122 for suppliers. A biomass-derived fuel not listed in section 95852.2(a) of the cap-and-trade regulation must be identified as non-exempt biomass-derived fuel. For a fuel listed under section 95852.2 of the cap-and-trade regulation, reporting entities must also meet the verification requirements in section 95131(i) of this article and the requirements of section 95852.1.1 of the cap-and-trade regulation, or the fuel must be identified as non-exempt biomass-derived fuel. Carbon dioxide combustion emissions from non-exempt biomass-derived fuel will be identified as non-exempt biomass-derived CO_2. The responsibility for obtaining verification of a biomass-derived fuel falls on the entity that is claiming there is not a compliance obligation for the fuel, as indicated in section 95852.2 of the cap-and-trade regulation.

***

(2) When reporting the use of forest derived wood and wood waste as identified in section 95852.2(a)(4) of the cap-and-trade regulation and harvested pursuant to any of the California Forest Practice Rules Title 14, California Code of Regulations, Chapters 4, 4.5 and 10 of~~r~~ the F~~f~~ederal National Environmental Policy Act, the reporting entity must report: the bone-dry mass received; ~~and~~information about the supplier, including the name, physical address, mailing address, contact person with phone number and e-mail address~~,~~; and the corresponding identification number under which the wood was removed.

***

(4) Reporting of fuel consumption from non-exempt biomass-derived fuel is subject to the requirements of section 95103(k) and reporting of emissions from non-exempt biomass-derived fuels is subject to the requirements of sections 95110 to 9515~~7~~8.

(k) *Measurement Accuracy Requirement.* The operator or supplier subject to the requirements of 40 CFR §98.3(i) must meet those requirements, except as otherwise specified in this paragraph. In addition, the following accuracy requirements apply to data used for calculating covered emissions and covered product data. ~~t~~The operator or supplier with covered product data or covered emissions equal to or exceeding 25,000 metric tons of CO_2e or a compliance obligation under the cap-and-trade regulation in any year of the current compliance period must meet the requirements of paragraphs (k)(1)-(10) below for calibration and measurement device accuracy. Inventory measurement, stock measurement, or tank drop measurement methods are subject to paragraph (11) below. The requirements of paragraphs (k)(1)-(11~~0~~) apply to fuel consumption monitoring devices, feedstock consumption monitoring devices, process stream flow monitoring devices, steam flow devices, product data measuring devices, mass and fluid flow meters, weigh scales, conveyer scales, gas chromatographs, mass spectrometers, calorimeters, and devices for determining density, specific gravity, and molecular weight. ~~Unless otherwise required by 40 CFR §98.3(i), t~~The provisions of ~~this section~~ paragraph (k)(1)-(11) do not apply to: stationary fuel combustion units that use the methods in 40 CFR §98.33(a)(4) to calculate CO_2 mass emissions; emissions reported as *de minimis* under section 95103(i); and devices that are solely used to measure parameters used to calculate emissions that are not covered emissions or that are not covered product data. The provisions of paragraphs (k)(1)-(9) and (k)(11) do not apply to stationary fuel combustion units that use the methods in 40 CFR Part 75 Appendix G §2.3 to calculate CO_2 mass emissions, but the provisions in paragraph (k)(10) are applicable to such units.

(1) Except as otherwise provided in sections ~~parts~~ 95103(k)(7) through (9), all ~~monitoring and sampling~~ flow meter and other measurement devices used to provide data for the GHG emissions calculations or covered product data must be calibrated prior to the year data collection is required to begin using the procedures specified in this section, and subsequently recalibrated according to the frequency specified in paragraph (4). ~~Each of these devices~~ A flow meter device consists of a number of individual components which might include a flow constriction component, mechanical component, and temperature and pressure measurement components. Each meter or measurement device must meet the applicable accuracy specification in section 95103(k)(6), however each individual component of a flow meter device is not required to meet the accuracy specifications. The procedures and methods used to quality-assure the data from each measurement device must be documented in the written monitoring plan required by section 95105(c).

(2) All flow meters and other measurement devices that provide data used to calculate GHG emissions or product data must be calibrated according to either the manufacturer's recommended procedures or a method specified in an applicable sub of 40 CFR 98. The calibration method(s) used must be documented in the monitoring plan required under section 95105(c), and are subject to verification under this article and review by ARB to ensure that measurements used to calculate GHG emissions or product data have met the accuracy requirements of this section.

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(4) Except as otherwise provided in sections 95103(k)(7) through (9), subsequent recalibrations of the flow meter and other measurement devices subject to the requirements of this section must be performed no less frequently than at one of the following time intervals, whichever is shortest:

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(E) Immediately upon replacement or repair of a device that is deemed out of calibration as determined in paragraph (6).

(~~E~~F) If the device manufacturer explicitly states in the product documentation that calibration is required at a period exceeding three years, the operator may follow the procedures in ~~sub~~paragraph (9) to obtain Executive Officer approval to relieve the operator from having to comply with provisions (A) and (C) of this subparagraph.

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(6) In addition to the specific calibration and field accuracy assessment requirements specified below, all flow meter and other measurement devices covered by this part, regardless of type, must be selected, installed, operated, and maintained in a manner to ensure ~~an~~ accuracy within ±5 percent~~%~~.

(A) Perform all mass and volume measurement device calibration as specified in the original equipment manufacturers (OEM) documentation. If OEM documentation is unavailable, calibrate as specified in 40 CFR §98.3(i)(2)-(3), except that a minimum of three calibration points must be used spanning the normal operating conditions. When using the three calibration points, one point must be at or near the zero point, one point must be at or near the upscale point, and one point at or near the mid-point of the devices operating range. If OEM documentation does not specify a method or is unavailable, and calibration methods specified in 40 CFR §98.3(i)(2)-(3) are not possible for a particular device, the procedures in section 95109(b) must be followed to obtain approval for an alternative calibration procedure. Additionally:

1. Pressure differential devices must be inspected at a frequency specified in ~~sub~~paragraph (k)(4) of this section. The inspection must be conducted as described in the appropriate part of ISO 5167-2 (2003), or AGA Report No 3 (2003) Part 2, both of which are incorporated by reference, or a method published by an organization listed in 40 CFR §98.7 applicable to the analysis being conducted. If the ~~plate~~ device fails any one of the tests then the meter shall be deemed out of calibration. If OEM guidance for a particular pressure differential device recommends against disassembly and inspection of the device, disassembly and inspection requirements in this paragraph do not apply. Documentation of OEM guidance must be made available to verifiers and ARB upon request.

    a. Records of all tests must be preserved pursuant to section 95105 and made available to verifiers and ARB upon request.
    b. Where inspection requirements apply, ~~In addition to the inspection,~~ the primary element must also 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.

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(B) Operators and suppliers may conduct an annual field accuracy assessment of mass and volume measurement devices to test for field accuracy in years between successive calibrations to ensure the device is maintaining measurement accuracy within ±5 percent. When performing a field accuracy assessment, the as-found condition must be recorded to ensure the device is measuring with accuracy within ±5 percent. Should a device be found to be operating outside the ±5 percent accuracy bounds, the device shall be deemed out of calibration. Records of all field accuracy assessments must clearly indicate the assessment procedure and the as-found condition, be preserved pursuant to section 95105, and be made available to verifiers and ARB upon request. Device accuracy may be assessed using one of the following options:

1. Engineering analysis;
2. OEM calibration guidance or other OEM recommended methods;
3. Standard industry practices; or
4. Portable instruments.

(C) Pursuant to paragraph (k)(10) of this section, in the event of a failed calibration or recalibration, operators or suppliers who choose not to perform the annual field accuracy assessment specified in paragraph

(6)(B) of this section for one or more mass or volume measurement devices must demonstrate data accuracy going back multiple years to the most recent successful calibration. Multiple years of data may be deemed invalid if accuracy cannot be demonstrated by other means. For operators and suppliers who conduct the annual field accuracy assessment, and a device is found to be out of calibration, accuracy must be demonstrated back to the most recent successful calibration or the most recent successful field accuracy assessment, whichever is most recent.

(7) ~~Financial transaction meters are exempted from the calibration requirements of section 95103(k) provided that the supplier and purchaser do not have any common owners and are not owned by subsidiaries or affiliates of the same company. For a flow meter or measurement device that has been previously calibrated in accordance with section 95103(k)(1) through (5), an additional calibration is not required by the date specified in section 95103(k)(1) if, as of that date, the previous calibration is still active (i.e., the device is not yet due for recalibration because the time interval between successive calibrations has not elapsed). In this case, the deadline for the successive calibrations of the flow meter or measurement device shall be set according to section 95103(k)(4).~~ The requirements of section 95103(k) do not apply under the following circumstances:

(A) Financial transaction meters are exempted from the calibration requirements of section 95103(k) if the supplier and purchaser do not have any common owners and are not owned by subsidiaries or affiliates of the same company. Financial transaction meters where the supplier and the purchaser do have common owners or are owned by subsidiaries or affiliates of the same company are exempt from the calibration requirements of section 95103(k) if one of the following is true:

1. The financial transaction meter is also used by other companies that do not share common ownership with the fuel supplier; or

2. The financial transaction meter is sealed with a valid seal from the county sealer of weights and measures or from a county certified designee; or

3. The financial transaction meter is operated by a third party.

(B) Upstream ethanol and additive meters used to ensure proper blendstock percentage for finished gasoline are exempted from the calibration requirements of section 95103(k).

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(9) In cases of continuously operating units and processes where calibration or inspection is not possible without operational disruption, the operator must demonstrate by other means to the satisfaction of the Executive Officer that measurements used to calculate GHG emissions and product data still meet the accuracy requirements of section 95103(k)(6). The Executive Officer must approve any postponement of calibration or required recalibration beyond January 1, 2012.

(A) A written request for postponement must be submitted to the Executive Officer not less than 30 days before the required calibration, recalibration or inspection date except in 2012, where the postponement request must be received by the reporting deadline in section 95103(e). The Executive Officer may request additional documentation to validate the operator's claim that the device meets the accuracy requirements of this section. The operator shall provide any additional documentation to ARB within ten (10) working days of a request by ARB.

(B) The request must include:

1. The date of the required calibration, recalibration, or inspection;
2. The date of the last calibration or inspection;
3. The date of the most recent field accuracy assessment, if applicable;
4. The results of the most recent field accuracy assessment, if applicable, clearly indicating a pass/fail status;
5. The proposed date for the next field accuracy assessment, if applicable;

~~3~~6. The proposed date for calibration, recalibration, or inspection which must be during the time period of the next scheduled shutdown. If the next shutdown will not occur within three years, this must be noted and a new request must be received every three years until the shutdown occurs and the calibration, recalibration or inspection is completed.

~~4~~7. A description of the meter or other device, including at a minimum:
   a. make,
   b. model,
   c. install date,
   d. location,
   e. annual emissions calculated or annual product data reported using data from the device,
   f. sources for which the device is used to calculate emissions or product data,
   g. calibration or inspection procedure,
   h. reason for delaying calibration or inspection,

i. proposed method to assure the accuracy requirements of section 95103(k)(6) are met,

j. name, title, phone number and e-mail of contact person capable of responding to questions regarding the device.

(10) If the results of an initial calibration, ~~or a~~ recalibration, or field accuracy assessment fail to meet the required accuracy specification, and the emissions or product data estimated using the data provided by the device represent more than 5 percent of total facility emissions or product data on an annual basis, the operator must demonstrate by other means to the satisfaction of the verifier or ARB that measurements used to calculate GHG emissions and product data still meet the ± 5% accuracy requirements going back to the last instance of successful field accuracy assessment or calibration of the device. Where the results of an initial calibration, recalibration, or field accuracy assessment fail to meet the accuracy specifications, ~~T~~the verifier shall note at a minimum a nonconformance as part of the emissions data verification statement.

(11) When using an inventory measurement, stock measurement, or tank drop measurement method to calculate volumes and masses, the method must be accurate to ±5 percent~~%~~ for the time periods required by this article, including annually for covered~~single~~ product data~~-components~~. Techniques used to quantify amounts stored at the beginning and end of these time periods are not subject to the calibration requirements of this part. Uncertainties in beginning and end amounts are subject to verifier review for material misstatement under section 95131(b)(12) of this article. If any devices used to measure inputs and outputs do not meet the requirements of paragraphs (1)-(10) above, the verifier must account for this uncertainty when evaluating material misstatements. Reported values must be calculated using the following equations:

Fuel consumed (volume or mass) = (inputs during time period – outputs during time period) + (amount stored at beginning of time period) – (amount stored at end of time period)

Product produced (volume or mass) = (outputs during time period - inputs during time period) + (amount stored at end of time period - amount stored at beginning of time period)

(l) *Reporting and Verifying Product Data*. The reporting entity must separately identify, quantify, and report all product data as specified in sections 95110-95123 and 95156 of this article. It is the responsibility of the reporting entity to obtain verification services for the product data. Product data will be evaluated for conformance and material misstatement independent of GHG emissions data. Covered product data is evaluated for material misstatement, while the remaining reported product data is evaluated for conformance. ~~The operator must not replace data when calculating product data.~~

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95104. Emissions Data Report Contents and Mechanism.

The reporting entities specified in section 95101 must develop, submit, and certify greenhouse gas emissions data reports to the Air Resources Board each year in accord with the following requirements.

(a) *General Contents.* In addition to the items specified at 40 CFR §98.3(c), each reporting entity must include in the emissions data report the following California information: ARB identification number, air basin, air district, county, ~~and~~ geographic location, and indicate whether the reporting entity qualifies for small business status pursuant to California Government Code 11342.610. Electricity generating units must also provide Energy Information Administration and California Energy Commission identification numbers, as applicable.

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95105. Recordkeeping Requirements.

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(c) *GHG Monitoring Plan for Facilities and Suppliers.* Each facility or supplier that reports under 40 CFR Part 98, each facility or supplier with covered emissions equal to or exceeding 25,000 MT~~mt~~CO_2e, and each facility or supplier with a compliance obligation under the cap-and-trade regulation in any year of the current compliance period, must complete and retain for review by a verifier or ARB a written GHG Monitoring Plan that meets the requirements of 40 CFR §98.3(g)(5). For facilities, the Plan must also include the following elements, as applicable:

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(d) *GHG Inventory Program for Electric Power Entities that Import or Export Electricity.*

***

(6) Reference to other independent or internal data management systems and records, including written power contracts and associated verbal or

electronic records, full or partial ownership, invoices, and settlements data used to document whether reported transactions are specified or unspecified and whether the requirements for adjustments to covered emissions pursuant to sections 95852(b)(1)(B), 95852(b)(4) and 95852(b)(5) of the cap-and-trade regulation are met;

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

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§ 95111. Data Requirements and Calculation Methods for Electric Power Entities.

The electric power entity who is required to report under section 95101 of this article must comply with the following requirements.

(a) *General Requirements and Content for GHG Emissions Data Reports for Electricity Importers and Exporters.*

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

***

(8) *Electricity Wheeled Through California.* The electric power entity must separately report electricity wheeled through California, aggregated by first point of receipt~~ outside California~~, and must exclude wheeled power transactions from reported imports and exports. When reporting electricity wheeled through California, the power entity must include the quantities of electricity wheeled through California as measured at the first point of delivery inside the state of California.

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(b) *Calculating GHG Emissions.*

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(2) *Calculating GHG Emissions from Specified Facilities or Units.* For electricity from specified facilities or units, the electric power entity must calculate

emissions using the following equation:

$$CO_2e = MWh \times TL \times EF_{sp}$$

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from each facility or unit claimed (MT of CO_2e).

MWh = Megawatt-hours of specified electricity deliveries from each facility or unit claimed.

EF_{sp} = Facility-specific or unit-specific emission factor published on the ARB Mandatory Reporting website and calculated using total emissions and transactions data as described below. The emission factor is based on data from the year prior to the reporting year.

EF_{sp} = 0 MT of CO_2e for facilities below the GHG emissions compliance threshold for delivered electricity pursuant to the cap-and-trade regulation during the first compliance period.

***

(3) *Calculating GHG Emissions of Imported Electricity Supplied by Specified Asset-Controlling Suppliers.* Based on annual reports submitted to ARB pursuant to section 95111(f), ARB will calculate and publish on the ARB Mandatory Reporting website the system emission factor for all ~~Bonneville Power Administration, an~~ asset-controlling suppliers recognized by the ARB. The reporting entity must calculate emissions for electricity supplied using the following equation:

$$CO_2e = MWh \times TL \times EF_{ACS}$$

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the specified electricity deliveries from ARB-recognized asset-controlling suppliers~~Bonneville Power Administration~~ (MT of CO_2e).

MWh = Megawatt-hours of specified electricity deliveries.

EF_{ACS} = Supplier-specific emission factor published on the ARB Mandatory Reporting website (MT CO_2e/MWh). ARB will assign the system emission factors for all asset-controlling suppliers ~~Bonneville Power Administration (BPA) a default system emission factor equal to 20 percent of the default emission factor for unspecified sources, or when available,~~ based on a previously verified GHG report submitted to ARB pursuant to section 95111(f)~~, beginning in the 2010 data year and meeting the requirements for asset controlling suppliers~~. The supplier-specific system emission factor is calculated annually by ARB. The calculation is derived from data contained in annual reports submitted pursuant to section 95111(f) that have received a positive or qualified positive verification statement. The emission factor is based on data from two years prior to the reporting year.

TL = Transmission loss correction factor.

TL = 1.02 when deliveries are not reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier.

TL = 1.0 when deliveries are reported as measured at a first point of receipt located within the balancing authority area of the asset-controlling supplier.

***

(5) Calculation of C~~c~~overed E~~e~~missions. For imported electricity with covered emissions as defined pursuant to section 95102(a), the electric power entity must calculate and report covered emissions pursuant to the equation in 95852(b)(1)(B) of the cap-and-trade regulation and include the following information:

CO_2e_{covered} = Sum of covered emissions defined pursuant to section 95102(a) and calculated pursuant to the equation in section 95852(b)(1)(B) of the cap-and-trade regulation (MT of CO_2e).

CO_2e_{unsp} = Sum of CO_2 equivalent mass emissions from imported electricity from unspecified sources (MT of CO_2e).

CO_2e_{sp} = Sum of CO_2 equivalent mass emissions from imported electricity that meets the requirements in section 95111(g) for reporting electricity from specified sources (MT of CO_2e).

$CO_2e_{\text{sp-not covered}}$ = Sum of CO_2 equivalent mass emissions from imported electricity that meets the requirements in section 95111(g) for reporting electricity from specified sources and is explicitly listed as ~~not covered~~ emissions without a compliance obligation pursuant to section 95852.2 of the cap-and-trade regulation (MT of CO_2e).

$CO_2e_{\text{RPS adjust}}$ = Sum of CO_2 equivalent mass emissions adjustment is calculated using the following equation for electricity generated by each eligible renewable energy resource located outside the state of California and registered with ARB by the reporting entity pursuant to section 95111(g)(1), but not directly delivered as defined pursuant to section 95102(a). Electricity included in the RPS adjustment must meet the requirements pursuant to section 95852(b)(4) of the cap-and-trade regulation (MT of CO_2e).

$$CO_2e_{RPS\_adjust} = MWh_{RPS} \times EF_{unsp}(MTCO_2e/MWh)$$

Where:

MWh_{RPS} = Sum of MWh generated by each eligible renewable energy resource located outside of the state of California, registered with ARB pursuant to section 95111(g)(1), and meeting requirements pursuant to section 95852(b)(4) of the cap-and-trade regulation.

$CO_2e_{QE\ adjust}$ = Sum of CO_2 equivalent mass emissions adjustment for qualified exports as defined in section 95102(a) and that meet the requirements pursuant to section 95852(b)(5) of the cap-and-trade regulation (MT of CO_2e).

CO_2e_{linked} = Sum of CO_2e mass emissions recognized by ARB pursuant to linkage under subarticle 12 of the cap-and-trade regulation (MT of CO_2e).

$$\cancel{CO_2e_{RPS\_adjust} = MWh_{RPS} \times AF}$$

~~Where:~~

~~MWh_{RPS} = Sum of MWh generated by each eligible renewable energy resource located outside of the state of California procured by the reporting entity, registered with ARB pursuant to section 95111(g)(1), and meeting requirements pursuant to section 95852(b)(4) of the cap-and-trade regulation.~~

~~AF = EF_{unsp} (MT CO_2e/MWh)~~

(c) ~~*GHG Emissions Data Report:*~~ *Additional Requirements for Retail Providers, excluding Multi-jurisdictional Retail Providers.* Retail providers must include the following information in the GHG emissions data report for each report year, in addition to the information identified in sections 95111(a)-(b) and (g).

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(4) Retail providers that report as electricity importers or exporters also must separately report electricity imported from specified and unspecified sources by other electric power entities to serve their load, designating the electricity importer. In addition, all imported electricity transactions documented by NERC e-Tags where the retail provider is the PSE at the sink must be reported.

(d) ~~*GHG Emissions Data Report:*~~ *Additional Requirements for Multi-Jurisdictional Retail Providers.* Multi-jurisdictional retail providers that provide electricity into

California at the distribution level must include the following information in the GHG emissions data report for each report year, in addition to the information identified in section 95111(a)-(b).

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(e) ~~GHG Emissions Data Report:~~ *Additional Requirements for WAPA and DWR.*

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(f) ~~*GHG Emissions Data Report: Additional*~~ *Requirements for Asset-Controlling Suppliers.* Owners or operators of electricity generating facilities or exclusive marketers for certain generating facilities may apply for an asset-controlling supplier designation from ARB. Approved asset-controlling suppliers may request that ARB calculate a supplier-specific emission factor pursuant to section 95111(b)(3).

~~Bonneville Power Administration request that ARB calculate its supplier-specific emission factor based on a previously verified GHG report that meets the requirements for asset-controlling suppliers, instead of a default system emission factor equal to 20 percent of the default emission factor for unspecified sources. An~~ To apply for asset-controlling supplier designation, the applicant ~~that chooses this option~~ must:

(1) Meet the requirements in this article, including reporting pursuant to section 95112 as applicable for each generating facility or unit in the supplier's fleet;
(2) Include in its emissions data report wholesale power purchased and taken (MWh) from specified and unspecified sources and wholesale power sold from specified sources according to the specifications in this section, and as required for ARB to calculate a supplier-specific emission factor;
(3) Retain for verification purposes documentation that the power sold by the supplier originated from the supplier's fleet of facilities and either that the fleet is under the supplier's operational control or that the supplier serves as the fleet's exclusive marketer;
(4) Provide the supplier-specific ARB identification number to electric power entities who purchase electricity from the supplier's system.
(5) To apply for and maintain asset-controlling supplier status, the entity shall submit as part of its emissions data report the following information, annually:
    (A) General business information, including entity name and contact information;
    (B) List of officer names and titles;
    (C) Data requirements per section 95111(b)(3);
    (D) Data requirements per section 95111(g)(1);
    (E) A list and description of electricity generating facilities for which the reporting entity is a generation providing entity pursuant to 95102(a); and
    (F) An attestation, in writing and signed by an authorized officer of the applicant, as follows:

"I certify under penalty of perjury under the laws of the State of California that I am duly authorized by [name of entity] to sign this attestation on behalf of [name of entity], that [name of entity] meets the definition of an asset-controlling supplier as specified in section 95102(a) of the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, title 17, California Code of Regulations, section 95100 et seq., and that the information submitted herein is true, accurate, and complete."

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

(g) *Requirements for Claims of Specified Sources of Electricity and for Eligible Renewable Energy Resources in the RPS Adjustment.*

Each reporting entity claiming specified facilities or units for imported or exported electricity must register its anticipated specified sources with ARB pursuant to subsection 95111(g)(1) and by February 1 following each data year to obtain associated emission factors calculated by ARB for use in the emissions data report required to be submitted by June 1 of the same year. Each reporting entity claiming specified facilities or units for imported or exported electricity must also meet requirements pursuant to section 95111(g)(2)-(5) in the emissions data report. Each reporting entity claiming an RPS adjustment, as defined in section 95111(b)(5), pursuant to section 95852(b)(4) of the cap-and-trade regulation must include registration information for the eligible renewable energy resources pursuant to section 95111(g)(1) in the emissions data report. Prior registration and section 95111(g)(2)-(5) do not apply to RPS adjustments. 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.

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

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

***

(M) Provide the serial numbers of Renewable Energy Credits (RECs) as specified below:

1. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment as well as whether the RECs have been placed in a retirement subaccount and

designated as retired for the purpose of compliance with the California RPS program.

2. RECs associated with electricity procured from an eligible renewable energy resource and reported as an RPS adjustment in a previous emissions data report year that later were withdrawn from the retirement subaccount, the associated emissions data report year the RPS adjustment was claimed, and date of REC withdrawal.
3. RECs associated with electricity generated, directly delivered, and reported as specified imported electricity and whether or not the RECs have been placed in a retirement subaccount.

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95112. Electricity Generation and Cogeneration Units.

The operator of a facility who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must report as specified below and comply with Subparts C and D of 40 CFR Part 98 (§§98.30 to 98.48), as applicable, in reporting emissions and other data from electricity generating and cogeneration units to ARB, except as otherwise provided in this section. Notwithstanding the above, the operator of a facility with total facility nameplate generating capacity of less than 1 MW may elect to follow section 95115 in reporting electricity generating units as general combustion sources, in lieu of the requirements of section 95112. If engineering estimation is used to report disposition of generated energy or energy flow data that are not used directly to determine emissions, facility operators must demonstrate accuracy of the chosen engineering estimation method.

(a) *Information About the Electricity Generating Facility.*

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(4) The disposition of generated electricity in MWh, reported at the facility-level, including:

(A) Generated electricity provided or sold to a retail provider or electricity marketer who distributes the electricity over the electric power grid for wholesale or retail customers of the grid. The operator must report the name of the retail provider or electricity marketer;
(B) Generated electricity provided or sold directly to particular end-users (as defined in section 95102). A reportable end-user includes any entity, under the same or different operational control, that is not a part of the

facility. Report each end-user's facility name, NAICS code, and ARB ID if applicable;

***

(5) The disposition of the thermal energy (MMBtu) generated by the cogeneration unit or bigeneration unit, if applicable, reported at the facility-level including:

(A) Thermal energy provided or sold to particular end-users (as defined in section 95102). A reportable end-user includes any entity, under the same or different operational control, that is not a part of the facility. Report each end-user's facility name, NAICS code, ARB ID if applicable, and the types of thermal energy product provided. Exclude from this quantity the amount of thermal energy that is vented, radiated, wasted, or discharged before the energy is provided to the end-user~~;~~.

(B) Thermal energy used for supporting power production~~,~~ that has been included in the quantity reported under paragraph 95112(b)(3) but that is not accounted for in the quantities reported under paragraphs 95112(a)(5)(A) and (C). This thermal energy quantity must not include steam directly used for power production, such as the steam used to drive a steam turbine generator to generate electricity. Activities for supporting power generation may include~~ing~~ steam used for power augmentation, NO_x control, sent to a de-aerator, or sent to a cooling tower~~;~~.

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(b) *Information About Electricity Generating Units.* Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating unit must include in the emissions data report the information listed in this paragraph. For aggregation of electricity generating units, the operator must~~that~~ meet the applicable criteria in 40 CFR §98.36(c)(1)-(4), unless otherwise specified in sections 95115(h) and 95112(b). ~~the operator may elect to report the following information for a group of aggregated units consisting of only electricity generating units of the same type, (e.g., all cogeneration units, all bigeneration units, or all generating units that are neither cogeneration or bigeneration in the grouping), except when 40 CFR 98.36(c) applies to the grouping, in lieu of separately reporting for each single unit.~~ For an electricity generation system (a cogeneration system, a bigeneration system, a combined cycle electricity generation system, or a system with boilers and steam turbine generators), the operator may aggregate all the units that are integrated into the system for the purpose of reporting data to ARB. Operators of Part 75 units may also aggregate units to the system level according to this paragraph, notwithstanding the limitation in 40 CFR §98.36(d)(1)(i). If there is more than one system present at the facility, each system must be reported separately. For electricity generating units that are not part of an integrated generation system, aggregation of electricity generating units is limited to units of the same type, as specified in section 95115(h). Operators of geothermal facilities, hydrogen fuel cells, and renewable electricity generating units must follow paragraph (e), (f), or (g) of this section, whichever is applicable, instead of paragraph (b) of this section. For bottoming cycle cogeneration units, the operator is not required to report the data specified in section 95112(b)(4)-(6) except for any fuels combusted for supplemental firing as specified in section 95112(b)(7).

(1) Basic information about the generating unit, including:
   (A) Nameplate generating capacity in megawatts (MW);
   (B) Prime~~r~~ mover technology;
   (C) For aggregation of units, provide a description of the individual equipment included in the aggregation;
   (D) If the unit generates both electricity and thermal energy, indicate whether the unit is a cogeneration or a bigeneration unit. If the unit is a cogeneration unit, indicate whether it is topping or bottoming cycle.

(2) Net and gross power generated, in megawatt hours (MWh).
(3) If the unit is a cogeneration or bigeneration unit, the operator must report the total thermal output (MMBtu), as defined in section 95102, that was generated by the unit. Exclude from this quantity the heat content of returned condensate and makeup water and steam used to drive a steam turbine generator for electricity generation.
(4) Fuel consumption by fuel type, reported in units of million standard cubic feet for gases, gallons for liquids, short tons for non-biomass solids, and bone dry short tons for biomass-derived solids.
(5) If not already required to be reported under 40 CFR §98.3~~5~~6(b) for Subarticle C units and §98.46 for Subarticle D units, annual CO_2, CH_4, and N_2O emissions from the unit, expressed in metric tons of each gas.
(6) If used to calculate CO_2 emissions and not already required to be reported under 40 CFR §98.36(e)(2)(ii)(C) and (iv)(C), report weighted or arithmetic average carbon content and high heat value by fuel type, whichever is used in calculating emissions as specified in 40 CFR §98.33.
(7) For cogeneration ~~units~~systems, where supplemental firing has been applied to support electricity generation or ~~industrial~~ thermal output, report the information in paragraphs (~~a~~b)(4)-(6). Indicate by fuel type the portion of the total fuel consumption (MMBtu) that is used for supplemental firing, and indicate the purpose of the supplemental firing.
(8) Other ~~steam used~~heat input for electricity generation. If the electricity generation unit uses additional heat input that is not already accounted for in paragraphs 95112(b)(4)-(6) (for example, if ~~Where~~ steam or heat is acquired from outside of the electricity generation system boundary or acquired from another facility for the generation of electricity), report the amount of acquired steam or heat (MMBtu)~~ for electricity generation~~. For bottoming cycle cogeneration units only, also report the input steam to the steam turbine (MMBtu) and the output of the heat recovery steam generator (MMBtu)~~ the amount of steam used (MMBtu) for generation of electricity~~.

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95113. Petroleum Refineries.

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(l) *Additional Product and Process Data.*

(1) ~~Finished Products.~~*Finished Products.* The operator must report production quantities for the data year of each petroleum product listed in Table C-1 of 40 CFR 98, ~~and~~ each additional transportation fuel product listed in Table MM-1 of 40 CFR Part 98 (standard cubic feet for gaseous products, barrels for liquid products, short tons for solid products), and calcined coke (short tons). For calcined coke, specify whether the calciner is integrated with the petroleum refinery operation. Among the products reported, only calcined coke and primary refinery products will be subject to review for material misstatement under the requirements of section 95131(b)(12).

(A) For calcined coke, the operator may voluntarily report the annual short tons of calcined coke for calendar years 2011 and 2012. If the operator chooses to report this 2011 and 2012 product data, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, the operator must report and verify the annual short tons of calcined coke.

(2) *Energy Intensity Index.* For refineries that participate in the Solomon Energy Reviews, the operator must report Solomon EII values for the applicable data year. ~~In the 2012 emissions data report the operator must report Solomon EII values for data years 2008, 2009, 2010, and 2011. In subsequent emissions data reports the operator must continue to report the Solomon EII value for the applicable data year.~~

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95114. Hydrogen Production.

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(i) *Transferred CO_2.* The operator must calculate and report the mass of all CO_2 captured, transferred off-site, and reported by the hydrogen production facility as a supplier of CO_2 using reporting provisions found in section 95123. Hydrogen production facilities should adjust reported emissions for CO_2 that is captured and sold or transferred off-site to avoid double counting.

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(ii) *Additional Product Data.* Operators must report the annual mass of hydrogen gas and ~~liquefied~~liquid hydrogen produced (~~short~~ metric tons) and specify if the hydrogen plant is an integrated refinery operation.

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95115. Stationary Fuel Combustion Sources.

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(c) *Choice of Tier for Calculating CO_2 Emissions.*

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(2) The operator may select the Tier 2 calculation method specified in 40 CFR §98.33(a)(2) for natural gas when it is pipeline quality as defined in section 95102 of this article, and for distillate fuels listed in Table 1 of this section. Tier 1 may be selected when the fuel supplier is providing pipeline quality natural gas measured in units of therms or million Btu. Equation C-2c of 40 CFR §98.33(a) may be selected for the units specified in paragraph (a) of this section.

***

(4) The operator must use either the Tier 3 or the Tier 4 calculation method specified under 40 CFR §98.33(a)(3)-(4) for any other fuel, including non-pipeline quality natural gas and fuel with emissions identified as non-exempt biomass-derived CO_2, subject to the limitations of 40 CFR §98.33(b)(4)-(5) requiring use of the Tier 4 method. The operator using Tier 3 must determine annual average carbon content with weighted fuel use values, as required by Equation C-2b of 40 CFR §98.33. When fuel mass or volume it measured by lot, the term "n" in Equation C-2b is substituted as the number of lots received in the year.

***

(e) *Procedures for Biomass CO_2 Determination.*

***

(3) When calculating emissions from a biomethane and natural gas mixture as described in 40 CFR §98.33(a)(2) using the annual MMBtu of fuel combusted in place of the product of Fuel and HHV in Equation C-2a, the operator must calculate emissions based on contractual deliveries of biomethane subject to the requirements of 95131(i), using the natural gas emission factor in the following equations:

$$E_{biomass\cancel{ethane}} = EF_{natural\ gas} \times MMBtu_{biomethane} \times 0.001$$

$$E_{natural\ gas} = EF_{natural\ gas} \times (MMBtu_{annual} - MMBtu_{biomethane}) \times 0.001$$

Where:

$E_{biomass}$	=	The annual biomass CO_2, CH_4 or N_2O emissions from biomethane (metric tons)
$E_{natual\ gas}$	=	The annual fossil CO_2, CH_4 or N_2O emissions from natural gas (metric tons)
~~E_{total}~~	~~=~~	~~The total annual CO_2, CH_4 or N_2O emissions from a source, determined using 40 CFR §98.33(a)(3)-(4) methodology or Sub D of 40 CFR 98 (metric tons)~~
$EF_{natural\ gas}$	=	The natural gas emission factor from Tables C-1 and C-2 of 40 CFR Part 98 (kg/MMBtu)
$MMBtu_{annual}$	=	The total delivered MMBtus for the reporting year based on utility bills or meters meeting the accuracy requirements of section 95103(k)
$MMBtu_{biomethane}$	=	The total biomethane deliveries subject to the requirements of section 95131(i) for the reporting year based on contractual deliveries

***

(h) *Aggregation of Units.* Facility operators may elect to aggregate units according to 40 CFR §98.36(c), except as otherwise provided in this paragraph. Facility operators that are reporting under more than one source category in paragraphs 95101(a)(1)(A)-(B)~~Tables A-3, A-4, and A-5 of 40 CFR Part 98, with the exception of 40 CFR Part 98 Subpart C,~~ and that elect to follow 40 CFR §98.36(c)(1), (c)(3) or (c)(4), must not aggregate units that belong to different source categories. For the purpose of unit aggregation, units subject to 40 CFR 98 Subarticle C that are associated with one source category must not be grouped with other Subarticle C units associated with another source category, except when 40 CFR §98.36(c)(2) applies. Aggregation of stationary fuel combustion units is limited to units of the same type, where the unit type categories are: boiler, reciprocating internal combustion engine, turbine, process heater, and other (none of the above). Units subject to section 95112 must use the criteria for aggregation in section 95112(b). Facility operators that choose to aggregate units according to the common stack provision in 40 CFR §98.36(c)(2) may report emissions according to 40 CFR §98.36(c)(2), but they must separately report the heat input (MMBtu) by fuel type for each individual unit or each group of units of the same type, such that the grouping of units still meets the limitations for unit aggregation specified elsewhere in this paragraph.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

***

§ 95119. Pulp and Paper Manufacturing

***

(d) *Additional Product Data.* In addition to the information required by 40 CFR §§98.276, the operator must report the annual production (air dried short tons) of recycled boxboard, recycled linerboard, recycled medium and tissue. For tissue, the operator must also report a description of the process used to produce tissue, such as through use of an air dryer.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95120. Iron and Steel Production

***

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion at a stationary combustion unit under 40 CFR §98.172(a), the operator must use a method in 40 CFR §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

***

(d) Additional Product Data. In addition to the information required by 40 CFR §98.176, the operator must report the annual production of ~~primary~~ iron and steel products in short tons, a description of the product(s), and, the process used to produce the products, such as use of an electric arc furnace.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95121. Suppliers of Transportation Fuels.

Any position holder, enterer, or refiner who is required to report under section 95101 of this article must comply with Subpart MM of 40 CFR Part 98 (§§98.390 to 98.398) in reporting emissions and related data to ARB, except as otherwise provided in this section.

(a) *GHGs to Report.*

***

(2) Refiners that supply fuel at a rack onsite, and position holders of fossil fuels and biomass-derived fuels and enterers outside the bulk transfer/terminal system of fossil fuels must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions that would result from the complete combustion or oxidation of each Blendstock, Distillate Fuel Oil or biomass-derived fuel (Biomass-Based Fuel and Biomass) listed in Table 2 of this section. ~~MM-1 or MM-2 of 40 CFR 98, except that~~ However, ~~Distillate Fuel Oil is limited to diesel fuel as defined in this regulation and except~~ reporting is not required for fuel ~~for~~ in which a final destination outside California can be demonstrated. No fuel shall be reported as finished fuel. Fuels must be reported as the individual Blendstock, Distillate Fuel Oil or biomass-derived fuel listed in Table 2 of this section. ~~40 CFR Part 98 Tables MM-1 and MM-2.~~

(b) *Calculating GHG emissions.*

(1) Refiners, position holders at California terminals, and enterers who bring fuel into California outside the bulk transfer/terminal system must use Equation MM-1 as specified in 40 CFR §98.393(a)(1) to estimate the CO_2 emissions that would result from the complete combustion of the fuel. Emissions must be based on the quantity of fuel removed from the rack (for refiners and position holders), fuel imported and not delivered to the bulk transfer/terminal system (by enterers), and fuel sold to unlicensed entities as specified in section 95121(d)(3) (by refiners). For fuels that are blended, emissions must be reported for each individual Blendstock, Distillate Fuel Oil or biomass-derived fuel listed in Table 2 of this section ~~40 CFR Part 98 Tables MM-1 and MM-2~~ separately, and not as motor gasoline (finished), biofuel blends, or other similar finished fuel. Emissions from denatured fuel ethanol must be calculated as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported. Emission factors must be taken from column C of 40 CFR 98 Table MM-1 or MM-2 as specified in Calculation Method 1 of 40 CFR §98.393(f)(1). If a position holder in diesel or biodiesel fuel does not have sealed or financial transaction meters at the rack, and the position holder is the sole position holder at the terminal, the position holder must calculate emissions based on the delivering entity's invoiced volume of fuel or a meter that meets the requirements of section 95103(k) either at the rack or at a point prior to the fuel going into the terminal storage tanks.

***

(d) *Data Reporting Requirements.* In addition to reporting the information required in 40 CFR §98.3(c), the following entities must also report the information identified below:

(1) California position holders must report the annual quantity in barrels, as reported by the terminal operator, of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in <u>Table 2 of this section,</u> ~~Tables MM-1 and MM-2 of 40 CFR Part 98~~ that is delivered across the rack in California,~~, except that distillate fuel oil is limited to diesel fuel and~~ except for fuel for which a final destination outside California can be demonstrated. Denatured fuel ethanol will be reported with the entire volume as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported.

(2) California position holders that are also terminal operators and refiners with on-site racks must report the annual quantity in barrels delivered across the rack of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in <u>Table 2 of this section,</u> ~~Tables MM-1 and MM-2 of 40 CFR Part 98, except distillate fuel oil is limited to diesel fuel and~~ except for fuel for which a final destination outside California can be demonstrated. Denatured fuel ethanol will be reported with the entire volume as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported. If there is only a single position holder at the terminal, and only diesel or biodiesel is being dispensed at the rack then the position holder must report the annual quantity of fuel using a meter meeting the requirements of section 95103(k) or billing invoices from the entity delivering fuel to the terminal.

(3) Refiners that supply fuel within the bulk transfer system to entities not licensed by the California Board of Equalization as a fuel supplier must report the annual quantity in barrels delivered of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in <u>Table 2 of this section,</u> ~~Tables MM-1 and MM-2 of 40 CFR Part 98, except Distillate Fuel Oil is limited to diesel fuel and~~ except for fuel for which a final destination outside California can be demonstrated. Denatured fuel ethanol will be reported with the entire volume as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported.

(4) Enterers of fossil-derived transportation fuels not directly delivered to the bulk transfer/terminal system must report the annual quantity in barrels, as reported on the bill of lading or other shipping documents of each Blendstock, Distillate Fuel Oil, or biomass-derived fuel listed in <u>Table 2 of this section,</u> ~~Tables MM-1 and MM-2 of 40 CFR Part 98 that is imported into California, except that Distillate Fuel Oil is limited to diesel fuel and~~ except for fuel for which a final destination outside California can be demonstrated. Denatured fuel ethanol will be reported with the entire volume as 100% ethanol only. The volume of denaturant is assumed to be zero and is not required to be reported.

(5) In addition to the information required in 40 CFR §98.396, ~~petroleum refineries~~ refiners must also report the volume of liquefied petroleum gas in barrels supplied in California as well as the volumes of the individual components as listed in 40 CFR 98 Table MM-1, except for fuel for which a final destination outside California can be demonstrated

*** [no changes to sections 95121(e); add Table 2 after section 95121(e)]

Table 2
Blendstocks, Distillate Fuel Oils, and Biomass-Derived Fuels Subject to Reporting under section 95121

CBOB—Summer
Regular
Midgrade
Premium
CBOB—Winter
Regular
Midgrade
Premium
RBOB—Summer
Regular
Midgrade
Premium
RBOB—Winter
Regular
Midgrade
Premium
Distillate Fuel Oils
Distillate No. 1
Distillate No. 2
Liquefied Petroleum Gas (LPG)
Ethane
Ethylene
Propane
Propylene
Butane
Butylene
Isobutane
Isobutylene
Pentanes Plus
Biomass-Derived Fuel
Ethanol (100%)
Biodiesel (100%, methyl ester)
Rendered Animal Fat
Vegetable Oil

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

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

***

(a) *GHGs to Report.*

***

(3) The California consignee for liquefied petroleum gas, compressed natural gas, or liquefied natural gas must ~~will~~ report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of the annual quantity of liquefied petroleum gas, compressed natural gas, and liquefied natural gas imported into the state, except for products for which a final destination outside California can be demonstrated

(b) *Calculating GHG Emissions.*

***

(9) The California consignee for liquefied petroleum gas must use calculation methodology 2 described in 40 CFR §98.403(a)(2) for calculating CO_2 emissions except that for liquefied petroleum gas t~~T~~able MM-1 of 40 CFR 98 must be used in place of Table NN-2. For liquefied petroleum gas, t~~T~~he consignee must sum the emissions from the individual components of the ~~liquefied petroleum~~ gas~~,~~ to calculate the total emissions. If the composition is not supplied by the producer, the consignee must use the default value for liquefied petroleum gas presented in Table C-1 of 40 CFR Part 98. The California consignee for compressed natural gas or liquefied natural gas must estimate CO_2 using calculation methodology 1 as specified in 40 CFR §98.403(a)(1), except that the product of HHV and Fuel is replaced by the annual MMBtu of natural gas received.

(10) The California consignee for liquefied petroleum gas, compressed natural gas, or liquefied natural gas must estimate and report CH_4 and N_2O emissions using equation C-8 and Table C-2 as described in 40 CFR §98.33(c)(1).

***

(d) *Data Reporting Requirements.*

***

(2) For the emissions calculation method selected under section 95122(b), local distribution companies must report all the data required by 40 CFR §98.406(b) subject to the following modifications:

***

(D) For each publicly-owned natural gas utility to which a local distribution company delivers natural gas, the local distribution companies must report the annual volumes ~~(~~in Mscf~~)~~, annual energy in ~~(~~MMBtu~~)~~, and the information required in 40 CFR §98.406(b)(12), including EIA number. These requirements are in addition to the requirements of 40 CFR §98.406(b)(6).

***

(5) In addition to the information required in 40 CFR §98.3(c), the California consignee for liquefied petroleum gas must report the annual quantity of liquefied petroleum gas imported as the total volume in barrels as well as the volume of its individual components for all components listed in 40 CFR 98 Table MM-1, if supplied by the producer, and report CO_2, CH_4, N_2O, and CO_2e annual mass emissions in metric tons using the calculation methods in section 95122(b). All California consignees of natural gas or natural gas liquids must record the annual quantities imported, in standard cubic feet or barrels, respectively, and report CO_2, CH_4, N_2O, and CO_2e annual mass emissions in metric tons separately for natural gas and natural gas liquids using the calculation methods in section 95122(b).

***

~~(f) *Additional Product Data.* The operator of a natural gas liquid fractionating facility must report the annual production of liquefied petroleum gas in barrels corrected to 60 degrees Fahrenheit.~~

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95123. Suppliers of Carbon Dioxide.

***

(b) *Missing Data Substitution Procedures.* The supplier must comply with 40 CFR §98.~~165~~425 when substituting for missing data, except for 2013 and later emissions data reports as otherwise provided below.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

***

§ 95130. Requirements for Verification of Emissions Data Reports.

The reporting entity who is <u>subject to verification</u> ~~required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a),~~ must obtain the services of an accredited verification body for purposes of verifying each emissions data report submitted under this article, as specified in section 95103(f).

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95131. Requirements for Verification Services.

***

(a) *Notice of Verification Services.*

***

(2) Documentation that the verification team has the skills required to provide verification services for the reporting facility. This shall include a demonstration that a verification team includes at least one member accredited <u>as a</u> ~~to provide~~ sector specific <u>verifier</u> ~~verification services~~ when required below:

***

(b) Verification services shall include, but are not limited to, the following:

***

(3) *Site Visits.* At least one accredited verifier in the verification team, including the sector ~~specialist~~ <u>specific verifier</u>, if applicable, shall at a minimum make one site visit, during each year full verification is required, to each facility for which an emissions data report is submitted. The verification team member(s) shall visit the headquarters or other location of central data management when the reporting entity is a retail provider, marketer, or fuel supplier. During the site visit, the verification team member(s) shall conduct the following:

***

(7) *Sampling Plan.* As part of confirming emissions data, product data, electricity transactions, or fuel transactions, the verification team shall develop a sampling plan that meets the following requirements:

***

(B) The verification team shall include in the sampling plan a ranking of emissions sources by amount of contribution to total CO_2 equivalent emissions for the reporting entity, and a ranking of emissions sources with the largest calculation uncertainty. The verification team shall also include in the sampling plan a ranking of the ~~single-~~product data ~~components~~ by units specified in the appropriate section of this article and a ranking of the ~~single-~~product data ~~components~~ with the largest uncertainty. As applicable and deemed appropriate by the verification team, fuel and electricity transactions shall also be ranked or evaluated relative to the amount of fuel or power exchanged and uncertainties that may apply to data provided by the reporting entity.

***

(9) *Emissions Data Report Modifications.* As a result of data checks by the verification team and prior to completion of a verification statement(s), the reporting entity must make any possible improvements or corrections to the submitted emissions data report, and submit a revised emissions data report to ARB. <u>Failure to do so will result in an adverse verification statement</u>. 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.

(10) *Findings.* To verify that the emissions data report is free of material misstatements, the verification team shall make its own determination of emissions for checked sources and product data for checked data and shall determine whether there is reasonable assurance that the emissions data report does not contain a material misstatement in GHG emissions reported for the reporting entity, on a CO_2 equivalent basis and/or a material misstatement in product data for the reporting entity, using the units required by the applicable parts of this article. ~~For product data, a material misstatement on a single product data component, except as otherwise specified in this article, will lead to an adverse product data verification statement.~~ To assess conformance with this article the verification team shall review the methods and factors used to develop the emissions data report for adherence to the requirements of this article and ensure that other requirements of this article are met.

***

(12) *Material Misstatement Assessment.* Assessments of material misstatement are conducted independently on total reported covered emissions and <u>total</u>

reported ~~single~~ covered product data ~~components~~ (units from the applicable parts of this article).

(A) In assessing whether an emissions data report contains a material misstatement, the verification team must separately determine whether the total reported covered emissions and total reported ~~single~~ covered product data ~~components~~ contain a material misstatement using the following equation:

$$\cancel{Percent\ error =} \sum \frac{[Discrepancies + Omissions + Misreporting]\ x\ 100\%}{\text{Total reported covered emissions/ or covered product data}}$$

$$Percent\ error\ (emissions) = \sum \frac{[Discrepancies + Omissions + Misreporting\ ]x\ 100\%}{Total\ reported\ covered\ emissions}$$

or

$$Percent\ error\ (product\ data) = \sum \frac{[Discrepancies + Omissions + Misreporting\ ]x\ 100\%}{Total\ covered\ product\ data}$$

Where:
"Discrepancies" means any differences between the reported covered emissions or~~/~~ covered product data and the verifier's review of ~~calculated~~ covered emissions~~/~~ or covered product data for a data source or product data subject to data checks in section 95131(b)(8).

"Omissions" means any covered emissions or covered product data the verifier concludes must be part of the emissions data report, but were not included by the reporting entity in the emissions data report.

"Misreporting" means duplicate, incomplete or other covered emissions the verifier concludes should, or should not, be part of the emissions data report or duplicate or other product data the verifier concludes should not be part of the emissions data report.

"Total reported covered emissions~~/~~ or covered product data" means the total annual reporting entity covered emissions or total reported ~~single~~ covered product data ~~components~~ for which the verifier is conducting a material misstatement assessment.

***

(i) *Verifying Biomass-derived Fuels.* In the absence of certification of the biomass-derived fuel by an accredited certifier of biomass-derived fuels, the verification body is subject to the requirements of subarticle 4 of this article as modified below when verifying biomass-derived fuel:

(1) *General biomass-derived fuel verification requirements.*

***

(C) *Completion of Verification Services for Biomass-derived Fuels.*

1. All information used for the verification of biomass-derived fuels must be included in the independent review as required in section 93131(c)(2) of this article.
2. Conformance for biomass-derived fuels is evaluated against the requirements of this article and sections 95852.1.1 and 95852.2 of the cap-and-trade regulation.
3. Reported c~~C~~arbon dioxide emissions from biomass-derived fuels are ~~included in the reporting entity's overall~~ considered an omission in the evaluation for material misstatement when~~.~~:
   a. ~~Any~~The fuel ~~that~~ does not conform with sections 95852.1.1 and 95852.2 of the cap-and-trade regulation and
   b. ~~it's~~ The emissions are ~~not~~ listed as ~~non-~~exempt biomass-derived CO_2. ~~will be considered an omission when evaluating for material misstatement under 95131(b)(12)(A) of this article.~~

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

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

***

(b) The Executive Officer may issue accreditation to verification bodies, lead verifiers, and verifiers that meet the requirements specified in this section.

***

(5) Sector Specific and Offset Project Specific Verifiers.

***

(B) *Offset Project Specific Verifier.* The applicant seeking to be accredited as an offset project specific verifier as specified in section 95977.1(b)~~(e)(4)(A)(iii)~~ of the cap-and-trade regulation must, in addition to meeting the requirements for accredited lead verifier or verifier qualification, meet one of the following requirements:

***

(c) *ARB Accreditation.*

(1) Within 90 days of receiving an application for accreditation as a verification body, lead verifier, verifier, sector specific verifier, or offset project specific verifier, the Executive Officer shall inform the applicant in writing either that the application is complete or that additional specific information is required to make the application complete.

(2) Upon a finding by the Executive Officer that an application for accreditation as a verification body, verifier, lead verifier, sector specific verifier, or offset project specific verifier is complete, meets all applicable regulatory requirements, and passes a performance review as defined in section 95102(a), the prescreening requirement is met and the applicant will be eligible to attend the verification training required by this section.

(3) Within 45 days following completion of the application process and all applicable training and examination requirements, the Executive Officer shall act to issue an Executive Order to grant or withhold accreditation for the verification body, lead verifier, sector specific verifier, offset project specific verifier or verifier.

(4) The Executive Order for accreditation is valid for a period of three years, whereupon the applicant may re-apply for accreditation as a verifier, lead verifier, sector specific verifier, offset project specific verifier, or verification body if the applicant has not been subject to ARB enforcement action under this article. All ARB approved general, sector specific, or offset project specific verification training and examination requirements applicable at the time of re-application must be met for accreditation to be renewed by the Executive Officer. In addition, the performance review requirement set forth in section 95132(c)(2) must be met for accreditation to be renewed by the Executive Officer.

***

(7) Within 15 working days of being notified of any corrective action in another voluntary or mandatory GHG program, an ARB accredited verification body, lead verifier, sector specific verifier, offset project specific verifier, or verifier shall provide written notice to the Executive Officer of the corrective action. That notification shall include reasons for the corrective action and the type of corrective action. The verification body or verifier must provide additional information to the Executive Officer upon request.

***

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95133. Conflict of Interest Requirements for Verification Bodies.

***

(b) The potential for a conflict of interest must be deemed to be high where:

(1) The verification body and reporting entity share any management staff or board of directors membership, or any of the senior management staff of the reporting entity have been employed by the verification body, or vice versa, within the previous ~~three~~ five years; or

(2) Within the previous five years, any staff member of the verification body or any related entity has provided to the reporting entity any of the following ~~non-verification~~ services:

***

(c) The potential for a conflict of interest shall be deemed to be low where the following conditions are met:

(1) N~~no~~ potential for a high conflict of interest is found ~~under~~ pursuant to section 95133(b); and

(2) A~~any~~ non-verification services provided by any member of the verification body or verification team to the reporting entity within the last five years are valued at less than 20 percent of the fee for the proposed verification services. Any independent greenhouse gas emissions verification provided by the verification body or verification team outside the jurisdiction of ARB is excluded from this financial assessment.

***

(e) *Conflict of Interest Submittal Requirements for Accredited Verification Bodies.*

(1) Before the start of any work related to providing verification services to a reporting entity, a verification body must first be authorized in writing by the Executive Officer to provide verification services. To obtain authorization the verification body shall submit to the Executive Officer a self-evaluation of the potential for any conflict of interest that the verification body, related entities ~~its ners~~, or any subcontractors performing verification services may have with the reporting entity for which it will perform verification services. The submittal shall include the following:

(A) Identification of whether the potential for conflict of interest is high, low, or medium based on factors specified in sections 95133(b), (c), and (d);

(B) Identification of whether the verification body, related entities, or any member of the verification team has previously provided verification services for the reporting entity or related entities and, if so, provide a description of such services and the years in which such ~~verification~~ services were provided;

(C) Identification of whether any member of the verification team, verification body, or related entity has engaged in ~~any non-verification~~ services of any nature, other than ARB verification services, with the reporting entity or related entities either within or outside California, during the previous ~~three~~ five years. If ~~non-verification~~ services other than ARB verification services have previously been provided, the following information shall also be submitted:

1. Identification of the nature and location of the work performed for the reporting entity or related entity and whether the work is similar to the type of work to be performed during verification, such as emissions inventory, auditing, energy efficiency, renewable energy, or other work with implications for the reporting entity's greenhouse gas emissions pursuant to this article ~~or the accounting of greenhouse gas emissions or electricity or fuel transactions~~;

2. The nature of past, present or future relationships of any member of the verification team, verification body, or related entities with the reporting entity or related entities including:

   a. Instances when any member of the verification team, verification body, or related entities has performed or intends to perform work for the reporting entity or related entities;
   b. Identification of whether work is currently being performed for the reporting entity or related entities, and if so, the nature of the work;
   c. How much work was performed for the reporting entity or related entities in the last ~~three~~ five years, in dollars;
   d. Whether any member of the verification team, verification body, or related entities has ~~any~~ contracts or other arrangements to perform work for the reporting entity or a related entity;
   e. How much work related to greenhouse gases ~~or electricity transactions~~ the verification team has performed for the reporting entity or related entities in the last ~~three~~five years, in dollars.

***

(f) *Conflict of Interest Determinations.* The Executive Officer must review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform verification services for the reporting entity.

***

(4) If the Executive Officer determines that the verification body and verification team have a medium potential for a conflict of interest, the Executive Officer shall evaluate the conflict of interest mitigation plan submitted pursuant to section 95133(d), and may request additional information from the applicant to complete the determination. In determining whether verification services may

proceed, the Executive Officer may consider factors including, but not limited to, the nature of previous work performed, the current and past relationships between the verification body, related entities, and its subcontractors with the reporting entity and related entities, and the cost of the verification services to be performed. If the Executive Officer determines that these factors when considered in combination demonstrate an acceptable level of potential conflict of interest, the Executive Officer will authorize the verification body to provide verification services

***

(g) *Monitoring Conflict of Interest Situations.*

***

(2) The verification body shall continue to monitor arrangements or relationships that may be present for a period of one year after the completion of verification services. During that period, within 30 days of the verification body or any verification team member entering into any contract with the reporting entity or related entity for which the body has provided verification services, the verification body shall notify the Executive Officer of the contract and the nature of the work to be performed, and revenue received. The Executive Officer, within 30 working days, will determine the level or conflict using the criteria in section 95133(a)-(d), if the reporting entity must reverify their emissions data report, and if accreditation revocation is warranted.

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

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

§95150. Definition of the Source Category.

(a) This source category consists of the following industry segments~~specified in 40 CFR §98.230(a)(1) through (a)(8) with the following additional source types~~:

(1) *Offshore petroleum and natural gas production.* Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include emissions from offshore drilling and exploration that is not conducted on production platforms.~~The onshore natural gas processing segment includes boosting stations;~~

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production means all equipment on a well-pad or associated with a well pad (including compressors, generators, dehydrators, storage vessels, and portable non-self-propelled equipment which includes well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels and all enhanced oil recovery (EOR) operations (both thermal and non-thermal), and all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island.~~The onshore natural gas transmission compression segment includes boosting stations.~~

(3) *Onshore natural gas processing.* Natural gas processing means the separation of natural gas liquids (NGLs) or non-ethane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO_2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant. This industry segment includes processing plants that

fractionate gas liquids, and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 MMscf per day or greater.

(4) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. In addition, a transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment.

(5) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process or equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

(6) *Liquefied natural gas (LNG) storage.* LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for regasification of the liquefied natural gas.

(7) *LNG import and export equipment.* LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system in California. LNG export equipment means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to California.

(8) *Natural gas distribution.* Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within California that is regulated by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§95151. Reporting Threshold~~ and Reporting Entity~~.

(a) The operator of a facility must report GHG emissions under this subarticle if the facility contains petroleum and natural gas systems and the facility meets the requirements of sections 95101(a)-(b). Facilities with source categories listed in section 95150 must report emissions if their stationary combustion and process emission sources emit 10,000 metric tons of CO_2 equivalent or more per year, or their stationary combustion, process, fugitive and vented emissions equal or exceed 25,000 metric tons of CO_2 equivalent or more per year.~~The operator of a facility with one or more source categories in 95150 who is required to report under 95101 of this article, and who is not eligible for abbreviated reporting under 95103(a), must comply with this subarticle in reporting GHG emissions from petroleum and natural gas systems to ARB.~~

(b) For applying the threshold defined in section 95101(b), natural gas processing facilities must also include owned or operated residue gas compression equipment. ~~In determining whether a facility in 95150 meets the reporting threshold defined in 95101(e), the operator must include combustion emissions from portable equipment that cannot move on roadways under its own power and drive train and that is stationed at a wellhead, including drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters. Natural gas processing facilities must also include owned or operated residue gas compression equipment.~~

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§95152. ~~GHGs~~Greenhouse Gases to Report.

(a) The operator of a facility must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraphs (b) through (i) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraphs (b) through (i) of this section, and stationary and portable combustion emissions as applicable and as specified in paragraph (j) of this section.

(b) For offshore petroleum and natural gas production, the operator must report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emissions, and flare emission source types as identified in the data collection and emissions estimation study conducted by the Bureau of Ocean Energy Management (BOEM) in compliance with 30 CFR §§250.302 through 304 (July 1, 2011), which is hereby incorporated by reference. Offshore platforms do not need to report portable emissions. In addition, offshore production facilities must report combustion emissions from supply and transportation vessels (e.g., ships and helicopters) used to transport personnel, equipment and products to and from the production facility using methods found in subpart C of 40 CFR Part 98.

(c) For an onshore petroleum and natural gas production facility, the operator must report CO_2, CH_4, and N_2O emissions from the following source types on a well-pad or associated with a well-pad:

(1) Metered natural gas pneumatic device and pump venting;
(2) Non-metered natural gas pneumatic device venting;
(3) Acid gas removal vents;
(4) Dehydrator vents;
(5) Well venting for liquids unloading;
(6) Gas well venting during well completions and workovers;
(7) Equipment and pipeline blowdowns;
(8) Onshore production and storage tanks;
(9) Well testing venting and flaring;
(10) Associated gas venting and flaring;
(11) Flare stack or other destruction device emissions;
(12) Centrifugal compressor venting;
(13) Reciprocating compressor rod packing venting;
(14) EOR injection pump blowdown;
(15) Crude oil and condensate CO_2 and CH_4;
(16) Produced water CO_2 and CH_4;
(17) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps); and
(18) The operator must use the methods in section 95153(y) and report under this subarticle the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas production facility as defined in section 95150. Stationary or portable equipment includes equipment which is integral to the extraction, processing, and movement of oil and/or natural gas; such as well pad construction equipment, well drilling and completion equipment, equipment used for abandoned well plugging and site reclamation, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(d) For onshore natural gas processing, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Acid gas removal vents;
(2) Dehydrator vents;
(3) Equipment and pipeline blowdowns;
(4) Flare stack or other destruction device emissions;
(5) Centrifugal compressor venting;
(6) Reciprocating compressor rod packing venting; and
(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(e) For onshore natural gas transmission compression, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Metered natural gas pneumatic device and pump venting;
(2) Non-metered natural gas pneumatic device venting;
(3) Equipment and pipeline blowdowns;
(4) Transmission storage tanks;
(5) Flare stack or other destruction device emissions;
(6) Centrifugal compressor venting;
(7) Reciprocating compressor rod packing venting; and
(8) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(f) For underground natural gas storage, the operator must report CO_2, CH_4, and N_2O from the following sources:

(1) Metered natural gas pneumatic device and pump venting;
(2) Non-metered natural gas pneumatic device venting;
(3) Equipment and pipeline blowdowns;
(4) Flare stack or other destruction device emissions;
(5) Centrifugal compressor rod packing venting;
(6) Reciprocating compressor rod packing venting; and
(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(g) For LNG storage, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Equipment and pipeline blowdowns;
(2) Flare stack or other destruction device emissions;
(3) Centrifugal compressor rod packing venting;
(4) Reciprocating compressor rod packing venting; and
(5) Equipment leaks from valves, pump seals, connectors, vapor recovery compressors, and other equipment leak sources.

(h) For LNG import and export equipment, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Equipment and pipeline blowdowns;
(2) Flare stack or other destruction device emissions;
(3) Centrifugal compressor rod packing venting;
(4) Reciprocating compressor rod packing venting; and
(5) Equipment leaks from valves, pump seals, connectors, vapor recovery compressors, and other equipment leak sources.

(i) For natural gas distribution, the operator must report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Meters, regulators, and associated equipment at above grade transmission-distribution transfer stations, including equipment leaks from connectors, block valves, orifice meters, regulators, and open ended lines;
(2) Equipment leaks from vaults at below grade transmission-distribution transfer stations;
(3) Meters, regulators, and associated equipment at above grade metering-regulating stations;
(4) Equipment leaks from vaults at below grade metering-regulating stations.
(5) Equipment and pipeline blowdowns;
(6) Service line equipment leaks;
(7) Report under section 95150 of this article the emissions of CO_2, CH_4, and N_2O emissions from stationary combustion sources following the methods in 95153(y); and
(8) Flare stack emissions.

(j) Except for facilities under onshore petroleum and natural gas production and natural gas distribution, the operator of a facility must report emissions of CO_2, CH_4, and N_2O for each stationary fuel combustion unit by following the requirements of section 95115 of this article. Operators of onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section.

(k) Operators of facilities must report CO_2 emissions captured and transferred off site by following the requirements of section 95123 of this article (suppliers of carbon dioxide).

~~(a) The operator must monitor, calculate and report CO_2, CH_4, and N_2O emissions as applicable from each source type specified in paragraphs (b) through (k) of this section, according to the requirements of s 95153 through 95156.~~

~~(b) For offshore petroleum and natural gas production, the operator must report emissions from all "stationary fugitive" and "stationary vented" sources as specified in 40 CFR §98.232(b).~~

~~(c) For onshore petroleum and natural gas production, the operator must report emissions from the source types specified in 40 CFR §98.232(c)(1)-(17) and (19)-(22), and additional applicable source types for which methods are specified in 95153. Additional data must be reported in aggregated and disaggregated form as specified in 95156(a)-(b).~~

~~(d) For onshore natural gas processing, the operator must report emissions from the sources identified in 40 CFR §98.232(d).~~

~~(e) For onshore natural gas transmission compression, the operator must report emissions the sources identified in 40 CFR §98.232(e), and natural gas-driven pneumatic pump venting.~~

~~(f) For underground natural gas storage, the operator must report emissions from the sources identified in 40 CFR §98.232(f), and natural gas-driven pneumatic pump venting. Additional data must be reported as specified in section 95156(c).~~

~~(g) For liquefied natural gas (LNG) storage, the operator must report emissions from the sources identified in 40 CFR §98.232(g).~~

~~(h) For LNG import and export equipment, the operator must report emissions from the sources identified in 40 CFR §98.232(h).~~

~~(i) For natural gas distribution, the operator must report emissions from the sources identified in 40 CFR §98.232(i),~~

~~(j) The operator in all applicable industry segments must report the~~ $\cancel{CO_2}$, $\cancel{CH_4}$, ~~and~~ $\cancel{N_2O}$ ~~emissions from each flare.~~

~~(k) The operator must report emissions of~~ $\cancel{CO_2}$, $\cancel{CH_4}$, ~~and~~ $\cancel{N_2O}$ ~~from each stationary fuel combustion unit by following the requirements of section 95115 of this article.~~

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

<u>§ 95153. Calculating GHG emissions.</u>

<u>The operator of a facility must calculate and report annual GHG emissions as prescribed in this section. The facility operator who is a local distribution company</u>

reporting under section 95122 of this article must comply with section 95153 for reporting emissions from the applicable source types in section 95152(i) of this article.

(a) *Metered Natural Gas Pneumatic Device and Pneumatic Pump Venting.* The operator of a facility who is subject to the requirements of sections 95153(a) and (b) must calculate emissions from a natural gas powered high bleed control device and pneumatic pump venting using the method specified in paragraph (a)(1) below when the natural gas flow to the device is metered. By January 1, 2015, natural gas consumption must be metered for all of the operator's pneumatic high bleed devices and pneumatic pumps. The operator may choose to also meter flow to any or all low bleed natural gas powered devices. For the purposes of this reporting requirement, high bleed devices are defined as all natural gas powered devices (both intermittent and continuous bleed devices) which bleed at a rate greater than 6 scf/hr. For unmetered devices the operator must use the method specified in section 95153(a). Vented emissions from natural gas driven pneumatic pumps covered in paragraph (d) of this section do not have to be reported under paragraph (a) of this section.

(1) The operator must calculate vented emissions for all metered natural gas powered pneumatic devices and pumps using the following equation:

$$E_m = \sum_1^n B_n \qquad \text{(Eq. 1)}$$

Where:

E_m = Annual natural gas emissions at standard conditions, in cubic feet, for all metered natural gas powered pneumatic devices.

n = Total number of meters.

B_n = Natural gas consumption for meter n.

(2) For both metered and unmetered natural gas powered devices, CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using methods in paragraphs (s) and (t) of this section.

(b) *Non-metered Natural Gas Pneumatic Device Venting.* The operator must calculate CH_4 and CO_2 emissions from all un-metered natural gas powered pneumatic low and high bleed devices using the following method:

$$E_{nm,i,x} = \sum_1^i \sum_1^x EF_i * T_{i,x} \qquad \text{(Eq. 2)}$$

Where:

$E_{nm,i,x}$ = Annual natural gas emissions at standard conditions for all unmetered natural gas powered devices and pumps (in scf).

i = Total number of unmetered component types.

x = Total number of component type i.

EF_i = Population emission factor for natural gas pneumatic device type i (scf/hour/component) listed in Tables 1A, 3, and 4 of Appendix A for onshore petroleum and natural gas production, onshore natural gas transmissions compression, and underground natural gas facilities, respectively.

$T_{i,x}$ = Total number of hours type i component x was in service. Default is 8760 hours.

(1) GHG (CO_2 and CH_4) volumetric and mass emissions must be calculated from volumetric natural gas emissions using methods in paragraphs (s) and (t) of this section.

(c) *Acid gas removal (AGR) vents.* For AGR vents (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), the operator must calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or through a flare, engine (e.g. permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using the applicable calculation methodologies described in paragraphs (c)(1)-(c)(10) below.

(1) *Calculation Methodology 1.* If the operator operates and maintains a CEMS that has both a CO_2 concentration monitor and volumetric flow rate meter, they must calculate CO_2 emissions under this subarticle by following the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in section 95115 (stationary fuel combustion sources). Alternatively, the operator may follow the manufacturer's instructions or industry standard practice. If a CO_2 concentration monitor and volumetric flow rate monitor are not available, the operator may elect to install a CO_2 concentration monitor and a volumetric flow rate monitor that comply with all the requirements specified for the Tier 4 Calculation Methodology in section 95115 (stationary fuel combustion sources). The calculation and reporting of CH_4 and N_2O emissions is not required as part of the Tier 4 requirements for AGRs.

(2) *Calculation Methodology 2.* If CEMS is not available but a vent meter is installed, the operator must use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation 3 of this section.

$$E_{a,CO2} = V_S * Vol_{CO2} \qquad \text{(Eq. 3)}$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_s = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in section 95154(b). Alternatively, the facility operator may follow the manufacturer's instructions for calibration of the vent meter.

Vol_{CO2} = Volume fraction of CO_2 content in the vent gas out of the AGR unit as determined in (c)(6) of this section.

(3) *Calculation Methodology 3.* If CEMS or a vent meter is not installed, the operator may use the inlet flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equation 4 of this section.

$E_{CO2} = V_{in} * [Y_{CO2-in} * (1 - Y_{H2S-spec}) - Y_{CO2-out} * (1 - Y_{H2S-in})]/(1 - Y_{H2S-spec} - Y_{CO2-out})$ (Eq. 4)

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_{in} = Total annual volume of natural gas flow into the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (c)(4) of this section.

Y_{CO2-in} = Mole fraction of CO_2 in natural gas into the AGR unit as determined in paragraph (c)(5) of this section.

$Y_{CO2-out}$ = Mole fraction of CO_2 in natural gas out of the AGR unit as determined in paragraph (c)(6) of this section.

$Y_{H2S-spec}$ = Mole fraction of H_2S in the natural gas out of the AGR unit as defined by the most recent emissions testing or no testing data is available, the performance specification of the AGR.

Y_{H2S-in} = Mole fraction of H_2S in natural gas into the AGR unit as determined in paragraph (c)(7) of this section.

(4) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in section 95154(b).

(5) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, either install a continuous gas analyzer or take monthly gas samples from the inlet gas stream to determine Y_{CO2-In} according to methods set forth in section 95154(b).

(6) Determine volume fraction of CO_2 content in natural gas or acid gas out of the AGR unit using one of the methods specified in paragraph (c)(6) of this section:

(A) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, the facility operator may install a continuous gas analyzer.

(B) If a continuous gas analyzer is not available or installed, monthly gas samples may be taken from the outlet gas stream to determine Y_{CO2} according to methods set forth in section 95154(b).

(7) Determine volume fraction of H_2S content monthly in natural gas or acid gas into the AGR unit using continuous gas analyzer data (if available), or other known or commonly accepted industry standard methods (if continuous data is not available).

(8) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (r) and (s) of this section.

(9) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraph (t) of this section.

(10) Determine if emissions from the AGR unit are recovered and transferred outside the facility. Adjust the emissions estimated in paragraph (c)(1) through (c)(9) of this section downward by the magnitude of emissions recovered and transferred outside the facility.

(d) *Dehydrator vents.* For dehydrator vents, calculate annual CH_4, CO_2, and N_2O emissions using any of the calculation methodologies described in paragraph (d) of this section.

(1) Calculate annual mass emissions from dehydrator vents using a software program which applies the Peng-Robinson equation of state (Equation 38 of section 95154) to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters determined by engineering estimate based on best available data must be used to characterize emissions from dehydrators.

(A) Feed natural gas flow rate.
(B) Feed natural gas water content.
(C) Outlet natural gas water content.
(D) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).
(E) Absorbent circulation rate.
(F) Absorbent type: including triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).
(G) Use of stripping gas.
(H) Use of flash tank separator (and disposition of recovered gas).
(I) Hours operated.
(J) Wet natural gas temperature and pressure.
(K) Wet natural gas composition. Determine this parameter by selecting one of the methods described in subparagraphs (1) – (4) below.

1. Use the wet natural gas composition as defined in section 95153(s)(2).
2. If wet natural gas composition cannot be determined using paragraph 95153(s)(2) of this section, select a representative analysis.
3. The facility operator may use an appropriate standard method published by a consensus-based standards organization or the facility operator may use an industry standard practice as specified in section 95154(b) to sample and analyze wet natural gas composition.
4. If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) Determine if the dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (d)(1) or (d)(4) of this section downward by the magnitude of emissions captured.

(3) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(A) Use the dehydrator vent volume and gas composition as determined in paragraph (d)(1) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(4) In the case of dehydrators that use desiccant, operators must calculate emissions from the amount of gas vented from the vessel when it is depressurized for the desiccant refilling process using Equation 5 of this section.

$$E_{s,n} = n(H * D^2 * \pi * \%G * P_2/(4 * P_1)) \qquad \text{(Eq. 5)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet.
n = number of fillings in reporting period.
H = Height of the dehydrator vessel (ft).
D = Inside diameter of the vessel (ft).
π = pi (3.1416)
%G = Percent of packed vessel volume that is gas (expressed as a decimal, e.g.,15% = 0.15).
P_1 = Atmospheric pressure (psia).
P_2 = Pressure of the gas (psia).

(5) For glycol dehydrators, both CH_4 and CO_2 mass emissions must be calculated from volumetric GHG_i emissions using calculations in paragraph (t) of this section. For dehydrators that use desiccant, both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(e) *Well venting for liquids unloadings.* Calculate CO_2 and CH_4 emissions from well venting for liquids unloading using one of the calculation methodologies described in paragraphs (e)(1), (e)(2) or (e)(3) of this section.

(1) *Calculation Methodology 1.* Calculate the total emissions for well venting for liquids unloading using Equation 6 of this section.

$$E_{s,n} = \sum_{p=1}^{W}\left[V_p * \left((0.37 * 10^{-3}) * CD_p^2 * WD_p * SP_p\right) + \sum_{p=1}^{V_p}\left(SFR_p * (HR_{p,q} - 1.0) * Z_{p,q}\right)\right] \qquad \text{(Eq. 6)}$$

Where:

$E_{S,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.
W = Total number of well venting events for liquids unloading for each basin.
$0.37x10^{-3}$ = {3.14(pi)/4}/{14.7x144}(psia converted to pounds per square feet).
CD_p = Casing diameter for each well, p, in inches.
WD_p = Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.
SP_p = Shut-in pressure or surface pressure for wells with tubing production and no packers or casing pressure for each well, p, in pounds per square inch absolute (psia).
V_p = Number of unloading events per year per well, p.
SFR_p = Average flow-rate of gas for well p, at standard conditions in cubic feet per hour. Use Equation 29 to calculate the average flow-rate at standard conditions.
$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading event, q.
1.0 = Hours for average well to blowdown casing volume at shut-in pressure.
$Z_{p,q}$ = If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

(A) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(2) *Calculation Methodology 2.* Calculate emissions from each well venting to the atmosphere for liquids unloading with plunger lift assist using Equation 7 of this section.

$$E_{S,n} = \sum_{p=1}^{W}\left[V_p * \left((0.37 * 10^{-3}) * TD_p^2 * WD_p * SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p * \left(HR_{p,q} - 0.5\right) * Z_{p,q}\right)\right] \quad \text{(Eq. 7)}$$

Where:
$E_{S,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.
W = Total number of well venting liquid unloading events at wells using plunger lift assist technology for each basin.
0.37×10^{-3} = {3.14(pi)/4}/{14.7 x 144} (psia converted to pounds per square feet).
TD_p = Tubing internal diameter for each well, p, in inches.
WD_p = Tubing depth to plunger bumper for each well, p, in feet.
SP_p = Flow-line pressure for each well, p, in pounds per square inch absolute (psia).
V_p = Number of unloading events per year for each well, p.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation 29 to calculate the average flow-line rate at standard conditions.
$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading, q.
0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.
$Z_{p,q}$ = If $HR_{p,q}$ is less than 0.5, then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5, then $Z_{p,q}$ is equal to 1.

(3) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(f) *Gas well venting during well completions and well workovers.* Using one of the calculation methodologies in this paragraph (f)(1) through (f)(5) below, operators must calculate CH_4, CO_2 and N_2O (when flared) annual emissions from gas well venting during both conventional completions and completions involving hydraulic fracturing in wells and both conventional well workovers and well workovers involving hydraulic fracturing.

(1) *Calculation Methodology 1.* Measure total gas flow with a recording flow meter (analog or digital) installed in the vent line ahead of a flare or vent id used. The facility operator must correct total gas volume vented for the volume of CO_2 or N_2 injected and the volume of gas recovered into a sales lines as follows:

$$E_a = V_M - V_{CO2/N2} - V_{SG} \quad \text{(Eq. 8)}$$

Where:

E_a = Natural gas emissions during the well completion or workover at actual conditions (m^3).
V_M = Volume of vented gas measured during well completion or workover (m^3).
$V_{CO2/N2}$ = Volume of CO_2 or N_2 injected during well completion or workover (m^3).
V_{SG} = Volume of natural gas recovered into a sales pipeline (m^3).

(A) All gas volumes must be corrected to standard temperature and pressure using methods in section(r).
(B) Calculate CO_2 and CH_4 volumetric and mass emissions using the methodologies in sections (s) and (t).

(2) *Calculation Methodology 2.*

(A) Record the well flowing pressure upstream (P_1) and downstream (P_2) of a well choke, upstream temperature and elapsed time of venting according to methods set forth in section 95154(b) to calculate the well backflow during well completions and workovers.

(B) The operator must record this data at a time interval (e.g., every five minutes) suitable to accurately describe both sonic and subsonic flow regimes.

(C) Sonic flow is defined as the flow regime where $P_2/P_1 \le 0.542$.

(D) Calculate the average flow rate during sonic conditions using Equation 9 of this section.

$$FR_a = 1.27 * 10^5 * A * \sqrt{187.08 * T_u} \qquad \text{(Eq. 9)}$$

Where:

FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

T_u = Upstream temperature (degrees Kelvin).

187.08 = Constant with units of $m^2/(sec^2 x K)$.

1.27×10^5 = Conversion from m^3/second to ft^3/hour.

(E) Calculate total gas volume vented during sonic flow conditions as follows:

$$V_S = FR_a * T_S \qquad \text{(Eq. 10)}$$

Where:

V_s = Volume of gas vented during sonic flow conditions (m^3).

T_S = Length of time that the well vented under sonic conditions (hours).

(F) For each of the sets of data points (T_u, P_1, P_2, and elapsed time under subsonic flow conditions) recorded as the well vented under subsonic flow conditions, calculate the instantaneous gas flow rate as follows:

$$FR_a = 1.27 * 10^5 * A * \sqrt{3430 * T_u * [(P_2/P_1)^{1.515} - (P_2/P_1)^{1.758}]} \qquad \text{(Eq. 11)}$$

Where:

FR_a = Instantaneous flow rate in cubic feet per hour, under actual subsonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

P_1 = Upstream pressure (psia).

T_u = Upstream temperature (degrees Kelvin).

P_2 = Downstream pressure (psia).

3430 = Constant with units of $m^2/(sec^2xK)$.

1.27×10^5 = Conversion from m^3/second to ft^3/hour.

(G) Calculate the total gas volume vented during subsonic flow conditions, V_{SS}, as the total volume under the curve of a plot of FR_a and elapsed time under subsonic flow conditions.

(H) Correct V_{SS} to standard conditions using the methodology found in paragraph (r) of this section.

(I) Sum the vented volumes during subsonic and sonic flow and adjust vented emissions for the volume of CO_2 and N_2 injected and the volume of gas recovered to a sales line as follows:

$$E_S = V_S + V_{SS} - V_{\frac{CO2}{N2}} - V_{SG} \qquad \text{(Eq. 12)}$$

Where:

E_s = Total volume of natural gas vented during the well completion or workover (scf).

V_s = Volume of natural gas vented during sonic flow conditions for the well completion or workover (scf) (see Eq. 10).

V_{ss} = Volume of natural gas vented during subsonic flow conditions for the well completion or workover (scf) (see 95153(f)(2)(G) above).

$V_{CO2/N2}$ = Volume of CO_2 or N_2 injected during the well completion or workover (scf).

V_{SG} = Volume of gas recovered to a sales line during the well completion or workover (scf).

(3) The volume of CO_2 or N_2 injected into the well reservoir during energized hydraulic fractures must be measured using an appropriate meter as described in section 95154(b) or using receipts of gas purchases that are used for the energized fracture job.

(A) Calculate gas volume at standard conditions using calculations in paragraph (r) of this section.

(4) Determine if the backflow gas from the well completion or workover is recovered with purpose designed equipment that separates natural gas from the backflow, and sends this natural gas to a flow-line (*e.g.*, reduced emissions completion or workover).

(A) Use the factor V_{SG} in Equation 8 of this section to adjust the emissions estimated in paragraphs (f)(1) through (f)(4) of this section by the magnitude of emissions captured using purpose designed equipment that separates saleable gas from the backflow as determined by engineering estimate based on best available data.

(B) Calculate gas volume at standard conditions using calculations in paragraph (r) of this section.

(5) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric total emissions using calculations in paragraphs (s) and (t) of this section.

(g) *Equipment and pipeline blowdowns.* Calculate CO_2 and CH_4 blowdown emissions from depressurizing equipment and natural gas pipelines to reduce system pressure for planned or emergency shutdowns resulting from human intervention or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraphs (d)(4) of this section) as follows:

(1) Calculate the unique physical volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves determined by engineering estimates based on best available data.

(2) Calculate the total annual venting emissions for unique volumes using either Equation 13 or 14 of this section.

$$E_{s,n} = N * \left(V\left(\frac{(459.67+T_s)P_a}{(459.67+T_a)P_s}\right) - V * C\right) \quad \text{(Eq. 13)}$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V = Unique physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet.

C = Purge factor that is 1 if the unique physical volume is not purged or zero if the unique physical volume is purged using non-GHG gases.

T_s = Temperature at standard conditions (60°F).

T_a = Temperature at actual conditions in the unique physical volume (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions in the unique physical volume (psia).

$$E_{s,n} = \sum_1^{PV} \sum_1^{N} [V((459.67 + T_S)(P_{(a,b,p)} - P_{(a,e,p)})/(459.67 + T_{a,p})\, P_S)] \quad \text{(Eq. 14)}$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

PV = Number of unique physical volumes blowndown.

N = Number of occurrences of blowdowns for each unique physical volume.

V = Total physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet for each blowdown "p".

T_s = Temperature at standard conditions (60°F).

$T_{a,p}$ = Temperature at actual conditions in the unique physical volume (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

$P_{a,b,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown "p".
$P_{a,e,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown "p"; 0 if blowdown volume is purged using non-GHG gases.

(3) Calculate both CH_4 and CO_2 volumetric and mass emissions using calculations in paragraph (s) and (t) of this section.
(4) Calculate total annual venting emissions for all blowdown vent stacks by adding all standard volumetric and mass emissions determined by Equation 13 or 14 and paragraph (g)(3) of this section.

(h) *Onshore production storage tanks.* Calculate emissions from occurrences of gas-liquid separator liquid dump valves not closing during the calendar year by using the method found in 95153(i).

(i) *Transmission storage tanks.* For vent stacks connected to one or more transmission condensate storage tanks, either water or hydrocarbon, without vapor recovery, in onshore natural gas transmission compression, the operator of a facility must calculate CH_4, CO_2 and N_2O annual emissions from condensate scrubber dump valve leakage as follows:

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in section 95154(a)(1) or by directly measuring the tank vent using a flow meter or high volume sampler according to methods in section 95154(b) through (d) for a duration of five minutes, or a calibrated bag according to methods in section 95154(b). Or the facility operator may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods in paragraph 95154(a)(5).
(2) If the tank vapors from the vent stack are continuous for five minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (i)(2) of this section to quantify annual emissions:

(A) Use a meter, such as a turbine meter, calibrate bag, or high flow sampler to estimate tank vapor volumes from the vent stack according to methods set forth in section 95154(b) through (d). If a continuous flow measurement device is not installed, the facility operator may install a flow measuring device on the tank vapor vent stack. If the vent is directly measured for five minutes under paragraph (i)(1) of this section to detect continuous leakage, this serves as the measurement.
(B) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in section 95154(a)(5).

(C) Use the appropriate gas composition in paragraph (s)(2)(C) of this section.
(D) Calculate GHG volumetric and mass emissions at standard conditions using calculations in paragraphs (r), (s), and (t) of this section, as applicable to the monitoring equipment used.

(3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.
(4) Calculate annual emissions from storage tanks to flares as follows:

(A) Use the storage tank emissions volume and gas composition as determined in paragraphs (i)(1) through (i)(3) of this section.
(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine storage tank emissions sent to a flare.

(j) *Well testing venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) well testing venting and flaring emissions as follows:
(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from all oil well(s) tested. Determine the production rate from all gas well(s) tested.
(2) If GOR cannot be determined from available data, then the facility operator must measure quantities reported in this section according to one of the two procedures in paragraph (j)(2) of this section to determine GOR.

(A) The facility operator may use an appropriate standard method published by a consensus-based standards organization if such a method exists; or
(B) The facility operator may use an industry standard practice as described in section 95154(b).

(3) Estimate venting emissions using Equation 15 or Equation 16 of this section.

$$E_{a,n} = GOR * FR * D \qquad \text{(Eq. 15)}$$

$$E_{a,n} = PR * D \qquad \text{(Eq. 16)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well(s) testing in cubic feet under actual conditions.
GOR = Gas to oil ratio, for well p in ~~sub~~-basin q, in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.
FR = Flow rate in barrels of oil per day for the oil well(s) being tested.
PR = Average annual production rate in actual cubic feet per day for the gas well(s) being tested.
D = Number of days during the year the well(s) is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (s) and (t) of this section.

(6) Calculate emissions from well testing to flares as follows:

(A) Use the well testing emissions volume and gas composition as determined in paragraphs (j)(1) through (3) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine well testing emissions from the flare.

(k) *Associated gas venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) associated gas venting and flaring emissions not in conjunction with well testing as follows:

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared.

(2) If GOR cannot be determined from available data, then use one of the two procedures in paragraph (k)(2) of this section to determine GOR.

(A) Use an appropriate standard method published by a consensus-based standards organization if such a method exists; or

(B) The facility operator may use an industry standard practice as described in section 95154(b).

(3) Estimate venting emissions using Equation 17 of this section.

$$E_{a,n} = \sum_{q=1}^{y} \sum_{p=1}^{x} GOR_{p,q} * V_{p,q} \qquad \text{(Eq.17)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions, at the facility level, from associated gas venting under actual conditions, in cubic feet.

$GOR_{p,q}$ = Gas to oil ratio, for well p in basin q, in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

$V_{p,q}$ = Volume of oil produced, for well p in basin q, in barrels in the calendar year during which associated gas was vented or flared.

x = Total number of wells in the basin that vent or flare associated gas.

y = Total number of basins that contain wells that vent or flare associated gas.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.

(6) Calculate emissions from associated gas to flares as follows:

(A) Use the associated natural gas volume and composition as determined in paragraph (k)(1) through (k)(4) of this section.
(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine associated gas emissions from the flare.

(l) *Flare stack or other destruction device emissions.* Calculate CO_2, CH_4 and N_2O emissions from a flare stack or other destruction device as follows:

(1) For the purposes of this reporting requirement, the facility operator must calculate emission from all flares, incinerators, oxidizers and vapor combustion units.
(2) If a continuous flow measurement device is installed on the flare or destruction device, the measured flow volumes must be used to calculate the flare gas emissions. If all of the gas or liquid sent to the flare or destruction device is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If a continuous flow measurement device is not installed on the flare or destruction device, a flow measuring device can be installed on the flare or destruction device or engineering calculations based on process knowledge or company records.
(3) If a continuous gas composition analyzer is not installed on gas or liquid supply to the flare or destruction device, use the appropriate gas composition for each stream of hydrocarbons going to the flare as follows:

(A) For onshore natural gas processing, when the stream going to the flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole percent in facility specific residue gas to transmissions pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams.
(B) For any applicable industry segment, when the stream going to the flare is a hydrocarbon product stream, such as methane, ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then the facility operator may use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(4) Determine flare combustion efficiency from manufacturer specifications. If not available, assume that flare combustion efficiency is 98 percent.

(5) Calculate GHG volumetric emissions at actual conditions using Equations 18, 19, and 20 of this section.

$$E_{a,CH4}(uncombusted) = V_a * (1-\eta) * X_{CH4} \qquad \text{(Eq. 18)}$$

$$E_{a,CO2}(uncombusted) = V_a * X_{CO2} \qquad \text{(Eq. 19)}$$

$$E_{a,CO2}(combusted) = \sum_{j=1}^{5}(\eta * V_a * Y_j * R_j) \qquad \text{(Eq. 20)}$$

Where:

$E_{a,CH4}$(uncombusted) = Contribution of annual un-combusted CH_4 emissions from flare stack in cubic feet, under actual conditions.

$E_{a,CO2}$ (uncombusted) = Contribution of annual un-combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

$E_{a,CO2}$(combusted) = Contribution of annual combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.

V_a = Volume of gas sent to flare in cubic feet, during the year.

η = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, η is zero.

X_{CH4} = Mole fraction of CH_4 in gas to the flare.

X_{CO2} = Mole fraction of CO_2 in gas to the flare.

Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, and pentanes-plus).

R_j = Number of carbon atoms in the gas hydrocarbon constituent j: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus.

(6) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(7) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (t) of this section.

(8) Calculate N_2O emissions from flare stacks using Equation 37 in paragraph (y) of this section.

(9) If the facility operator operates and maintains a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor, calculate only CO_2 emissions for the flare. The facility operator must follow the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and record keeping requirements for Tier 4 in section 95115. If a CEMS is used to calculate flare stack emissions, the requirements specified in paragraphs (l)(1) through (l)(8) are not required. If a CO_2 concentration monitor and volumetric flow rate monitor are not available, the facility operator may elect to install a CO_2 concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Methodology in section 95115 of this article (stationary fuel combustion sources).

(10) The flare emissions determined under paragraph (l) of this section must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(11) If source types in section 95153 use Equations 18 through 20 of this section, use volume under actual conditions for the parameter, V_a, in these equations.

(m) *Centrifugal compressor venting.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents as follows:

(1) For each centrifugal compressor with a rated horsepower of 250hp or greater covered by sections 95152(c)(12), (d)(5), (e)(6), (f)(5), (g)(3), and (h)(3) the operator must conduct an annual measurement in each operating mode in which it is found for more than 200 hours in a calendar year. Measure emissions from all vents (including emissions manifolded to common vents) including wet seal oil degassing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement:

(A) Operating mode, blowdown valve leakage through the blowdown vent, wet seal and dry seal compressors.
(B) Operating mode, wets seal oil degassing vents.
(C) Not operating depressurized mode, unit isolation valve leakage through open blowdown vent, without blind flanges, wet seal and dry seal compressors.

1. For the not operating depressurized mode, each compressor must be measured at least once in any three consecutive calendar years. If a compressor is not operated and has blind flanges in place throughout the three year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the three year period, it must be measured in the standby depressurized mode.

(D) An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the MT_m variable in place of actual measured values for centrifugal compressors that are operated for no more than 200 hours in a calendar year and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.

(2) For wet seal oil degassing vents, determine vapor volumes sent to an atmospheric vent or flare, using a temporary meter such as a vane anemometer or permanent flow meter according to section 95154(b) of this section. If a permanent flow meter is not installed, the operator may install a permanent flow meter on the wet seal oil degassing tank vent.
(3) For blowdown valve leakage and isolation valve leakage to open ended vents, use one of the following methods: Calibrated bagging or high volume sampler according to methods set forth in sections 95154(c) and 95154(d), respectively. For through valve leakage, such isolation valves, the facility

operator may install a port for insertion of a temporary meter, or a permanent flow meter, on the vents.

(4) To determine Y_i, use gas composition data from a continuous gas analyzer if a continuous gas analyzer is installed, or quarterly measurements of gas composition where a continuous gas analyzer is not installed.

(5) Estimate annual emissions using the flow measurement and Equation 21 of this section.

$$E_{s,i,m} = \sum_m MT_m * T_m * Y_i * (1 - CF) \qquad \text{(Eq. 21)}$$

Where:

$E_{s,i,m}$ = Annual GHG (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour during operating mode m as described in sections (m)(1)(A) through (m)(1)(C).

T_m = Total time the compressor is in the mode for which $E_{s,i}$ is being calculated, in the calendar year in hours.

Y_i = Mole fraction of GHG_i in the vent gas.

CF = Fraction of centrifugal compressor vent gas that is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of gas that is directed to the fuel gas or vapor recovery system.

(6) For each centrifugal compressor with a rated horsepower of less than 250hp covered by sections 95152(c)(12), (d)(5), (e)(6), (f)(5), (g)(3), and (h)(3), the operator must calculate annual emissions from both wet seal and dry seal centrifugal compressor vents using Equation 22 of this section.

$$E_{s,i} = Count * EF_i \qquad \text{(Eq. 22)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from centrifugal compressors (<250hp) in cubic feet.

Count = Total number of centrifugal compressors less than 250hp.

EF_i = Emission factor for GHGi. Use 1.2×10^7 standard cubic feet per year per compressor for CH_4 and 5.30×10^5 standard cubic feet per year per compressor for CO_2 at 60°F and 14.7 psia.

(7) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (t) of this section.

(8) Calculate emissions from seal oil degassing vent vapors to flares as follows:

(A) Use the seal oil degassing vent vapor volume and gas composition as determined in paragraphs (m)(2) through (m)(4) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (l) of this section to determine degassing vent vapor emissions from the flare.

(n) *Reciprocating compressor venting.* Calculate CH_4 and CO_2, and N_2O (when flared) emissions from all reciprocating compressor vents as follows:

(1) For each reciprocating compressor with a rated horsepower of 250hp or greater covered in sections 95152(c)(13), (d)(6), (e)(7), (f)(6), (g)(4), and (h)(4) the facility operator must conduct an annual measurement for each compressor in each operating mode in which it is found for more than 200 hours in a calendar year. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement as follows:

(A) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.

(B) Operating mode, reciprocating rod packing emissions.

(C) Not operating depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

1. For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the three year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the three year period, it must be measured in the standby depressurized mode.
2. An engineering estimate approach based on similar equipment specifications and operating conditions may be used to determine the MT_m variable in place of actual measured values for reciprocating compressors that are operated for no more than 200 hours in a calendar year and used for peaking purposes in place of metered gas emissions if an applicable meter is not present on the compressor.

(2) If reciprocating rod packing and blowdown vent are connected to an open-ended vent line, use one of the following two methods to calculate emissions:

(A) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in sections 95154(c) and 95154(d), respectively.

(B) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents and unit isolation valve leakage through blowdown vents according to methods set forth in section 95154(b). If a permanent flow meter is not installed, the facility operator may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents such as unit isolation valves on not operating, depressurized compressors, use an acoustic detection device according to methods set forth in section 95154(a).

(3) If reciprocating rod packing is not equipped with a vent line use the following method to calculate emissions:

(A) The facility operator must use the methods described in section 95154(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or other vent with a closed distance piece.

(B) Measure emissions found in paragraph (n)(2)(A) of this section using an appropriate meter, or calibrated bag, or high volume sampler according to the methods set forth in sections 95154(b), (c), and (d) respectively.

(4) To determine Y_i, use gas composition data from a continuous gas analyzer if a continuous gas analyzer is installed, or quarterly measurements of gas composition where a continuous gas analyzer is not installed.

(5) Estimate annual emissions using the flow measurement and Equation 23 of this section.

$$E_{s,i,m} = \sum_m MT_m * T_m * Y_i * (1 - CF) \qquad \text{(Eq. 23)}$$

Where:

$E_{s,i,m}$ = Annual GHG_i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet.

T_m = Total time the compressor is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year in hours.

Y_i = Mole fraction of GHG_i in the vent gas.

CF = Fraction of reciprocal compressor vent gas that is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of gas that is directed to the fuel gas or vapor recovery system.

(6) For each reciprocating compressors with a rated horsepower of less than 250hp, the operator must calculate annual emissions using Equation 24 of this section.

$E_{s,i} = Count * EF_i$ (Eq. 24)

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from reciprocating compressors in cubic feet.

Count = Total number of reciprocating compressors for the facility operator.

EF_i = Emission factor for GHG_i. Use 9.48 x 10^3 standard cubic feet per year per compressor for CH_4 and 5.27 x 10^2 standard cubic feet per year per compressor for CO_2 at 60°F and 14.7 psia.

(7) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (s) and (t) of this section.

(o) *Leak detection and leaker emission factors.* The operator must use the methods described in section 95154(a) to conduct leak detection(s) of equipment leaks from all components types listed in sections 95152(c)(17), (d)(7), (e)(8), (f)(7), (g)(5), (h)(5), and (i)(1). This paragraph (o) applies to component types in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Component types in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (o) and do not need to be reported. If equipment leaks are detected for sources listed in this paragraph (o), calculate equipment leak emissions per component type per reporting facility using Equations 25 or 26 of this section for each component type. Use Equation 25 for industry segments listed in section 95150(a)(1) – (a)(7). Use Equation 26 for natural gas distribution facilities as defined in section 95150(a)(8).

$E_{s,i} = GHG_i * \sum_{p=1}^{x}(EF * T_p)$ (Eq. 25)

$E_{s,i} = GHG_i * \sum_{q=t-n+1}^{t}\sum_{p=1}^{x}(EF * T_{p,q})$ (Eq. 26)

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each component type in cubic feet, as specified in (o)(1) through (o)(8) of this section.

X = Total number of each component type.

EF = Leaker emission factor for specific component types listed in Table 1A and 2 through 7 of Appendix A.

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1 x 10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1 x 10^{-2} for CO_2 or use the experimentally determined gas composition for CO_2 and CH_4.

T_p = The total time the component, p, was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey (if not found leaking in the previous survey) or the beginning of the calendar year (if it was found leaking in the previous survey) or the beginning of the calendar year (if it was found leaking in the previous survey). For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

t = Calendar year of reporting.

n = The number of years over which one complete cycle of leak detection is conducted over all the Transmission – Distribution (T-D) transfer stations in a natural gas distribution facility; $0 < n \leq 5$. For the first (n-1) calendar years of reporting the summation in Equation 26 should be for years that the data is available.

$T_{p,q}$ = The total time the component, p, was found leaking and operational, in hours, in year q. If one leak detection survey is conducted, assume the component was leaking for the entire period n. If multiple leak detection surveys are conducted, assume the component found to be leaking has been leaking since the previous survey) or the beginning of the calendar year (if it was found to be leaking in the previous survey). For the last leak detection survey in the cycle, assume that all leaking components continue to leak until the end of the cycle.

(1) The operator must select to conduct either one leak detection survey in a calendar year or multiple complete leak detection surveys in a calendar year. The number of leak detection surveys selected must be conducted during the calendar year.

(2) Onshore petroleum and natural gas production facilities must use the appropriate default leaker emissions factors listed in Table 1A of Appendix A for all leaks from equipment types in the table.

(3) Onshore natural gas processing facilities must use the appropriate default leaker emission factors listed in Table 2 of Appendix A for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(4) Onshore natural gas transmission facilities shall use the appropriate default leaker emission factors listed in Table 3 of Appendix A for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(5) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table 4 of Appendix A for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(6) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table 5 of Appendix A for equipment leaks detected from valves, pump seals, connectors, and other equipment.

(7) LNG import and export facilities shall use the appropriate default leaker emission factors listed In Table 6 of Appendix A for equipment leaks detected from valves, pump seals, connectors, and other equipment.

(8) Natural gas distribution facilities for above ground transmission-distribution transfer stations, shall use the appropriate default leak emission factors listed in Table 7 of Appendix A for equipment leaks detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Leak detection at natural gas distribution facilities is only required at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do meet the definition of transmission-distribution transfer stations are not required to perform component leak detection under this section.

(A) Natural gas distribution facilities may choose to conduct leak detection at the T-D transfer stations over multiple years, not exceeding a five year period to cover all T-D transfer stations. If the facility chooses to use the multiple year option then the number of T-D transfer stations that are monitored in each year should be approximately equal across all years in the cycle without monitoring the same station twice during the multiple year survey.

(p) *Population count and emission factors.* This paragraph applies to emissions sources listed in sections 95152(f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4), (i)(5), and (i)(6) on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (p) of this section and do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation 27 of this section.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \quad \text{(Eq. 27)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG emissions at standard conditions from each component type in cubic feet.

$Count_s$ = Total number of this type of emission source at the facility. For onshore petroleum and natural gas production, average component counts are provided by major equipment piece in Table 1B and Table 1C of Appendix A. Use average component counts as appropriate for operations in Western U.S., according to Table 1B of Appendix A for 2012 data. For 2013 calendar year emissions and onwards, actual components counts for individual facilities must be used. Underground natural gas storage shall count the components listed for population emission factors in Table 4. LNG storage shall count the number of vapor recovery compressors. LNG import and export shall count the number of vapor recovery compressors. Natural gas distribution shall count the meter/regulator runs as described in paragraph (p)(6) of this section.

EF_s = Population emission factor for the specific component type, as listed in Table 1A and Tables 3 through Table 7 of Appendix A. Use appropriate emission factor for operations in Western U.S., according to Table 1(A) – 1(C) of Appendix A. EF for meter/regulator runs at above grade metering-regulator stations is determined in Equation 28 of this section.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas as defined in paragraph (s)(2) of this ; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} for CO_2 or use the experimentally determined gas composition for CO_2 and CH_4.

T_s = Total time that each component type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (t) of this section.

(2) Onshore petroleum and natural gas production facilities must use the appropriate default population emission factors listed in Table 1A of Appendix A for equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other. Major equipment and components associated with gas wells are considered gas service components in reference to Table 1A of Appendix A and major natural gas equipment in reference to Table 1B of Appendix A. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table 1A of Appendix A and major crude oil equipment in reference to Table 1C of Appendix A. Where facilities conduct EOR operations the emissions factor listed in Table 1A of Appendix A shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the methodologies described in this paragraph (p)(2). The same methodology must be used for the entire calendar year.

(A) *Component Count Methodology 1.* For all onshore petroleum and natural gas production operations in the facility perform the following activities:

1. Count all major equipment listed in Table 1B and Table 1C of Appendix A. For meters/piping, use one meters/piping per well-pad.

2. Multiply major equipment counts by the average component counts listed in Table 1B and 1C of Appendix A for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table 1A of Appendix A for operations in Eastern and Western U.S. according to the mapping in Table 1B of Appendix A.

(B) *Component Count Methodology 2.* Count each component individually for the facility. Use the appropriate factor in Table 1A of Appendix A for operations in the Western U.S.

(3) Underground natural gas storage facilities for storage wellheads must use the appropriate default population emission factors listed in Table 4 of Appendix A for equipment leak from connectors, valves, pressure relief valves and open ended lines.

(4) LNG storage facilities must use the appropriate default population emission factors listed in Table 5 of Appendix A for equipment leak from vapor recovery compressors.

(5) LNG import and export facilities must use the appropriate emission factor listed in Table 6 of Appendix A for equipment leak from vapor recovery compressors.

(6) Natural gas distribution facilities must use the appropriate emission factors as described in paragraph (p)(6) of this section.

(A) Below grade metering-regulating stations; distribution mains; and distribution services, must use the appropriate default population emission factors listed in Table 7 of Appendix A. Below grade T-D transfer stations must use the emission factor for below grade metering-regulating stations.

(B) Emissions from all above grade metering-regulating stations (including above grade T-D transfer stations) must be calculated by applying the emission factor calculated in Equation 28 and the total count of metering/regulator runs at all above grade metering-regulating stations (inclusive of T-D transfer stations) to Equation 27. The facility wide emission factor in Equation 28 will be calculated by using the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in Equation 26 and the count of meter/regulator runs located at above grade transmission-distribution transfer stations that were monitored over the years that constitute one complete cycle as per (p)(1) of this section. A meter on a regulator run is considered one meter regulator run. Facility operators that do not have above grade T-D transfer stations shall report a count of above grade metering-regulating stations only and do not have to comply with section 95157(c)(16)(T).

$$EF = E_{s,i}/(8760 * Count) \qquad \text{(Eq. 28)}$$

Where:

EF = Facility emission factor for a meter/regulator run per component type at above grade meter/regulator run for GHG_i in cubic feet per meter/regulator run per hour.

$E_{s,i}$ = Annual volumetric GHG_i emissions, CO_2 or CH_4, at standard condition from each component type at all above grade T-D transfer stations, from Equation 27.

Count = Total number of meter/regulator runs at all T-D transfer stations that were monitored over the years that constitute one complete cycle as per paragraph (p)(8)(i) of this section.

8760 = Conversion to hourly emissions.

(q) *Offshore petroleum and natural gas production facilities.* Operators must report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimate study conducted by BOEM in compliance with 30 CFR §§250.302 through 304 (July 1, 2011), which is hereby incorporated by reference.

(1) Offshore production facilities under BOEM jurisdiction must report the same annual emissions as calculated and reported by BOEM in data collection and emissions estimate study published by BOEM and referenced in 30 CFR §§250.302 through 304 (July 1, 2011) Gulfwide Offshore Activities Data System (GOADS).

(A) The BOEM data is collected and reported every other year. In years where the BOEM data is not available, use the previous year's BOEM data and adjust the emissions based on the operating time for the facility relative to the operating time in the previous year's BOEM data.

(2) Offshore production facilities that are not under BOEM jurisdiction must use monitoring methods and calculation methodologies published by BOEM and referenced in 30 CFR §§250.302 through 304 (July 1, 2011) to calculate and report emissions (GOADS).

(A) The BOEM data is collected and reported every other year. In years where the BOEM data is not available, use the previous year's BOEM data and adjust the emissions based on the operating time for the facility relative to the operating time in the previous year's BOEM data.

(3) If BOEM discontinues or delays their data collection effort by more than 4 years, then offshore operators must once in every 4 years use the most recent BOEM data collection and emissions estimation methods to report emission from the facility sources.

(4) For either the first or subsequent year of reporting, offshore facilities either within or outside of BOEM jurisdiction that were not covered in the previous

BOEM data collection cycle must use the BOEM data collection and emissions estimation methods published by BOEM and referenced in 30 CFR §§250.302 through 304 (July 1, 2011) (GOADS) to report.

(r) *Volumetric emissions.* If equation parameters in section 95153 are already at standard conditions, which results in volumetric emissions at standard conditions, then this paragraph does not apply. Calculate volumetric emissions at standard conditions as specified in paragraphs (r)(1) or (2) of this section, with actual pressure and temperature determined by engineering estimates based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions using actual natural gas emission temperature and pressure, and Equation 29 of this section.

$$E_{s,n} = E_{a,n} * (459.67 + T_s) * P_a/((459.67 + T_a) * P_s) \qquad \text{(Eq. 29)}$$

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet except $E_{s,n}$ equals ($FR_{s,p}$) for each well p, when calculating either subsonic or sonic flow rates under section 95153(f).

$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (60°F).

T_a = Temperature at actual conditions (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

(2) Calculate GHG volumetric emissions at standard conditions using actual GHG emissions temperature and pressure, and Equation 30 of this section.

$$E_{s,i} = E_{a,i} * (459.67 + T_s) * P_a/((459.67 + T_a) * P_s) \qquad \text{(Eq. 30)}$$

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard conditions in cubic feet.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (60°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (Psia).

(3) Facility operators using 68°F for standard temperature may use the ratio 519.67/527.67 to convert volumetric emissions from 68°F to 60°F.

(s) *GHG volumetric emissions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (s)(1) and (s)(2) of this section, with mole fraction of GHGs in the natural gas determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation 31 of this section.

$$E_{s,i} = E_{s,n} * M_i \qquad \text{(Eq. 31)}$$

Where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions in cubic feet.
$E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet.
M_i = Mole fraction of GHG i in the natural gas.

(2) For Equation 31 of this section, the mole fraction, M_i, must be the annual average mole fraction for each basin or facility, as specified in paragraphs (s)(2)(A) through (s)(2)(G) of this section.

(A) GHG mole fraction in produced pipeline quality natural gas for onshore petroleum and natural gas production facilities. If the facility has a continuous gas composition analyzer for produced natural gas, the facility operator must use an annual average of these values for determining the mole fraction. The composition of non-pipeline quality natural gas must be determined as specified in section 95115(c)(4).

(B) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline system for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If the facility has a continuous gas composition analyzer on feed natural gas, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(C) GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(D) GHG mole fraction in natural gas stored in the underground natural gas storage industry segment. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(E) GHG mole fraction in natural gas stored in the LNG storage industry segment. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(F) GHG mole fraction in natural gas stored in the LNG import and export industry segment. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(G) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities. If the facility has a continuous gas composition analyzer, the facility operator must use these values for determining the mole fraction. If the facility does not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in section 95154(b).

(t) *GHG mass emissions.* Calculate GHG mass emissions in carbon dioxide equivalent by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation 32 of this section.

$$Mass_i = E_{s,i} * \rho_i * 10^{-3} \qquad \text{(Eq. 32)}$$

Where:

$Mass_i$ = GHG_i (either CH_4, CO_2, or N_2O) mass emissions in metric tons GHG_i.

$E_{s,i}$ = GHG_i (either CH_4, CO_2, or N_2O) volumetric emissions at standard conditions, in cubic feet.

P_i = Density of GHG_i. Use 0.0526 kg/ft^3 for CO_2 and N_2O, and 0.0192 kg/ft^3 for CH_4 at 60°F and 14.7 psia.

(u) *EOR injection pump blowdown.* Calculate CO_2 pump blowdown emissions from EOR operations using critical CO_2 injection as follows:

$$Mass_{CO2} = N * V_v * R_c * GHG_i * 10^{-3} \qquad \text{(Eq. 33)}$$

Where:

$Mass_{CO2}$ = Annual EOR injection gas venting emissions in metric tons from blowdowns.

N = Number of blowdowns for the equipment in the calendar year.
R_c = Density of critical phase EOR injection gas in kg/ft^3. The facility operator may use an appropriate standard method published by published by a consensus based organization if such a method exists or the facility operator may use an industry standard practice to determine density of super-critical emissions.

GHG_i = Mass fraction of GHG_i in critical phase injection gas.
$1x\ 10^{-3}$ = Conversion factor from kilograms to metric tons.

(v) *Crude Oil and Condensate Dissolved CO_2 and CH_4.* The operator must calculate dissolved CO_2 and CH_4 in crude oil and condensate. Emissions must be reported for crude oil and condensate sent to a storage tank or ponds and holding facilities.

(1) Calculate CO_2 and CH_4 emissions from crude oil and condensate using Equation 33A:

$$E_{CO2/CH4} = (S_{cc} * V_{cc})(1 - (VR * CE)) \qquad \text{(Eq. 33A)}$$

Where:

$E_{CO2/CH4}$ = Annual CO_2 or CH_4 emissions in metric tons.
S_{cc} = Mass of CO_2 or CH_4 liberated in a flash liberation test per barrel of produced water (as determined in paragraph (v)(1)(A)1. or mass of CO_2 or CH_4 recovered in a VRU per barrel of crude oil and condensate (as determined in paragragh (v)(1)(A)2.
V_{cc} = Barrels of crude oil or condensate sent to tank, pond or holding facility annually.
VR = Percentage of time the vapor recovery unit was operational (expressed as a decimal).
CE = Collection efficiency of the vapor recovery system (expressed as a decimal).

(A) S_{pw} (the mass of CO_2 or CH_4 per barrel of crude oil and condensate) shall be determined using one of the following methods:

1. Flash liberation test. Measure the amount of CO_2 and CH_4 liberated from crude oil and condensate when the crude oil or condensate changes temperature and pressure from well stream to standard atmospheric conditions using a sampling methodology and a flash liberation test such as adopted Gas Processor Association standards. The flash liberation test results must provide the metric tons of CO_2 and CH_4 liberated per barrel of crude oil and condensate.

2. Vapor recovery system method. For storage tank systems connected to a vapor recovery system, calculate the mass of CO_2 and CH_4 liberated from crude oil and condensate by sampling (under representative operating conditions) and analysis of the vapor recovery unit (VRU) gas stream to determine the mass of CO_2 and CH_4 captured by the vapor recovery system per barrel of crude oil or condensate produced. A gas analysis of the processed vapor is required to determine the mole percentage of CO_2 and CH_4 in the gas stream and to calculate the annual emission rate. Vapor recovery system measurements may include gases from crude oil and condensate and produced water.

(B) Emissions resulting from the destruction of the VRU gas stream shall be reported using the Flare Stack reporting provisions in paragraph (l) of this section.

(w) *Produced Water Dissolved CO_2 and CH_4.* The operator must calculate dissolved CO_2 and CH_4 in produced water. Emissions must be reported for produced water sent to a storage tank or ponds and holding facilities.

(1) Calculate CO_2 and CH_4 emissions from produced water using Equation 34:

$$E_{CO2/CH4} = (S_{pw} * V_{pw})(1 - VR * CE) \qquad \text{(Eq. 34)}$$

Where:

$E_{CO2/CH4}$ = Annual CO_2 or CH_4 emissions in metric tons.

S_{pw} = Mass of CO_2 or CH_4 liberated in a flash liberation test per barrel of produced water (as determined in paragraph (w)(1)(A)1. or mass of CO_2 or CH_4 recovered in a VRU per barrel of produced water (as determined in paragragh (w)(1)(A)2.

V_{pw} = Barrels of produced water sent to tank, pond or holding facility annually.

VR = Percentage of time the vapor recovery unit was operational (expressed as a decimal).

CE = Collection efficiency of the vapor recovery system (expressed as a decimal).

(A) S_{pw} (the mass of CO_2 or CH_4 per barrel of produced water) shall be determined using one of the following methods:

1. Flash liberation test. Measure the amount of CO_2 and CH_4 liberated from produced water when the water changes temperature and pressure from well stream to standard atmospheric conditions using a sampling methodology and a flash liberation test such as adopted Gas

Processor Association standards. The flash liberation test results must provide the metric tons of CO_2 and CH_4 liberated per barrel of produced water.

2. Vapor recovery system method. For storage tank systems connected to a vapor recovery system, calculate the mass of CO_2 and CH_4 liberated from produced water by sampling (under representative operating conditions) and analysis of the VRU gas stream to determine the mass of CO_2 and CH_4 captured by the vapor recovery system per barrel of water produced. A gas analysis of the processed vapor is required to determine the mole percentage of CO_2 and CH_4 in the gas stream and to calculate the annual emission rate. Vapor recovery system measurements may include gases from produced water and crude oil and condensate.

(B) Emissions resulting from the destruction of the VRU gas stream shall be reported using the Flare Stack reporting provisions in paragraph (l) of this section.

(2) EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir are exempt from paragraph (v) of this section .

(x) ***Reserved***

(y) *Onshore petroleum and natural gas production and natural gas distribution combustion emissions.* Calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment, except as specified in paragraph (y)(3) and (y)(4) of this section as follows:

(1) If a fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C of 40 CFR Part 98, or is a blend containing one or more fuels listed in Table C-1, calculate emissions according to paragraph (y)(1)(A). If the fuel combusted is natural gas and is of pipeline quality specification and has a minimum high heat value of 970 Btu per standard cubic foot, use the calculation methodology described in paragraph (y)(1)(A) and the facility operator may use the emission factor provided for natural gas as listed in Subpart C, Table C-1. If the fuel is natural gas, and is not pipeline quality calculate emissions according to paragraph (y)(2). If the fuel is field gas, process vent gas, or a blend containing field gas or process vent gas, calculate emissions according to paragraph (y)(2).

(A) For fuels listed in Table C-1 or a blend containing one or more fuels listed in Table C-1 of Subpart C, calculate CO_2, CH_4, and N_2O emissions according to any Tier listed in section 95115.

(2) For fuel combustion units that combust field gas, process vent gas, a blend containing field gas or process vent gas, or natural gas that is not of pipeline quality, calculate combustion emissions as follows:

(A) The operator may use company records to determine the volume of fuel combusted in the unit during the reporting year.

(B) If a continuous gas composition analyzer is installed and operational on fuel supply to the combustion unit, the operator must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If a continuous gas composition analyzer is not installed on gas to the combustion unit, the facility operator must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in paragraph (s)(2) of this section.

(C) Calculate GHG volumetric emissions at actual conditions using Equations 35 and 36 of this section:

$$E_{a,CO2} = (V_a * Y_{CO2}) + \eta * \sum_{j=1}^{5} V_a * Y_j * R_j \qquad \text{(Eq. 35)}$$

$$E_{a,CH4} = V_a * (1 - \eta) * Y_{CH4} \qquad \text{(Eq. 36)}$$

Where:

$E_{a,CO2}$ = Contribution of annual CO_2 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of fuel gas sent to combustion unit in cubic feet, during the year.

Y_{CO2} = Concentration of CO_2 constituent in gas sent to combustion unit.

$E_{a,CH4}$ = Contribution of annual CH_4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

η = Fraction of gas combusted for portable and stationary equipment determined using an engineering estimation. For internal combustion devices, a default of 0.995 can be used.

Y_j = Concentration of gas hydrocarbon constituent j (such as methane, ethane, propane, butane and pentanes plus) in gas sent to combustion unit.

R_j = Number of carbon atoms in the gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus, in gas sent to combustion unit.

Y_{CH4} = Concentration of methane constituent in gas sent to combustion unit.

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

$$Mass_{N2O} = (1\,x\,10^{-3}) * Fuel * HHV * EF \qquad \text{(Eq. 37)}$$

Where:

$Mass_{N2O}$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons N_2O).

Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = For the higher heating value for field gas or process vent gas, use 1.235×10^{-3} mmBtu/scf for HHV.

EF = Use 1.0×10^{-4} kg N_2O/mmBtu.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions or include these emissions for threshold determination in section 95101(e). The operator must report the type and number of each external fuel combustion unit.

(4) Internal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr (or equivalent of 130 horsepower), do not need to report combustion emissions or include these emissions for threshold determination in section 95101(e). The operator must report the type and number of each internal fuel combustion unit.

~~The operator who is a local distribution company reporting under section 95122 of this article must comply with 40 CFR §98.233 in reporting emissions from the applicable source types in section 95152(e) (i) of this article. Other operators must comply with 40 CFR §98.233 in reporting applicable emissions by source type, except as otherwise provided in this section.~~

~~(a) *Natural Gas Pneumatic High Bleed Device and Pneumatic Pump Venting.* The operator who is subject to the requirements of 40 CFR §98.233(a) and (c) must calculate emissions from natural gas high bleed flow control device and pneumatic pump venting using the method specified in paragraph (a)(1) below when the device or pump is metered. By January 1, 2015, natural gas consumption must be metered for all of the operator's pneumatic high bleed devices and pneumatic pumps. For the purposes of this reporting requirement, high bleed devices are defined as all natural gas powered devices (both intermittent and continuous bleed devices) which bleed at a rate greater than 6 scf/hr. For unmetered devices the operator must use the method specified in 40 CFR §98.233(a) and (c) as applicable. Vented emissions from natural gas driven pneumatic pumps covered in paragraph (d) of this section do not have to be reported under paragraph (a) of this section.~~

~~(1) The operator must calculate vented emissions for all metered pneumatic high bleed devices and pneumatic pumps using the following equation:~~

$$\cancel{E_m = \sum_{1}^{n} B_n}$$

~~Where:~~

~~E_m = Annual natural gas emissions at standard conditions, in cubic feet for all pneumatic high bleed devices and pneumatic pumps where gas is metered.~~

~~n = Total number of meters.~~

~~B_n = Natural gas consumption for meter n.~~

~~(2) For both metered and unmetered devices and pumps, CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.~~

~~(b) *Natural Gas Pneumatic Low Bleed Device Venting.* The operator must calculate CH_4 and CO_2 emissions from natural gas pneumatic low bleed devices using either the method specified in paragraph (a)(1) of this or the method specified in 40 CFR §98.233(a). For the purposes of this reporting requirement, low bleed devices are defined as all natural gas powered devices (both intermittent and continuous bleed devices) which bleed at a rate less than or equal to 6 scf/hr.~~

~~(1) CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using calculations in paragraphs (s) and (t) of this section.~~

~~(c) *Acid Gas Removal (AGR) Vent Stacks.* The operator who is subject to the reporting requirements of 40 CFR §98.233(d) for AGR vents must use the applicable Calculation Methodology 1, 2, or 3 in 40 CFR §98.233(d). The operator who uses Calculation Methodology 3 must also use the methodology in paragraph (c)(1) below.:~~

~~(1) To measure natural gas volume into the AGR unit, the operator must use the following formula:~~

$$\cancel{E_{a,CO2} = V_{IN}\left(Vol_{IN} - Vol_{OUT}\right)}$$

~~Where:~~

~~$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.~~

~~V_{IN} = Total annual volume of natural gas flow into the AGR unit in cubic feet per year at actual conditions using methods specified in paragraph (c)(2) of this section.~~

~~Vol_{IN} = Volume fraction of CO_2 content in natural gas into the AGR unit as determined in 40 CFR §98.233(d)(7).~~

~~Vol_{OUT} = Volume fraction of CO_2 content in natural gas out of the AGR unit as determined in 40 CFR §98.233(d)(8).~~

~~(2) If the operator measures natural gas volume out of the AGR, the operator must use the following formula:~~

$$\cancel{E_{a,CO2} = \left[V_{OUT} / 1 - \left(Vol_{IN} - Vol_{OUT}\right)\right]\left(Vol_{IN} - Vol_{OUT}\right)}$$

~~Where:~~

~~$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.~~

~~V_{OUT} = Total annual volume of natural gas flow out of AGR unit in cubic feet per year at actual conditions using methods specified in paragraph (c)(2) of this section.~~

~~Vol_{IN} = Volume fraction of CO_2 content in natural gas into the AGR unit as determined in paragraph (c)(4) of this section.~~

~~Vol_{OUT} = Volume fraction of CO_2 content in natural gas out of the AGR unit as determined in paragraph (c)(4) of this section.~~

~~(3) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in 40 CFR §98.234(b).~~

~~(4) If a continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream to determine Vol_{CO2} according to methods set forth in 40 CFR §98.234(b).~~

~~(5) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream to determine Vol_{IN} or Vol_{OUT} according to methods set forth in 40 CFR §98.234(b).~~

~~(6) Determine volume fraction of CO_2 content in natural gas out of the AGR unit using one of the methods specified in 40 CFR §98.233(d)(8).~~

~~(A) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, the operator may install a continuous gas analyzer.~~

~~(B) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream to determine Vol_{O} according to methods set forth in 40 CFR §98.234(b).~~

~~(7) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (r) of this section.~~

~~(8) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraph (t) of this section.~~

~~(9) Determine if emissions from the AGR unit are recovered and transferred outside the facility. The operator who is required to report these transferred emissions under section 95123 of this article is not required to report CO_2 transferred off-site in this section.~~

~~(d) *Dehydrator Vent Stacks.* The operator who is subject to the reporting requirements for dehydrator vents in 40 CFR §98.233(e) must use Calculation Methodology 1 in 40 CFR §98.233(e) and follow the requirements in 40 CFR §98.233(e)(3)-(5). The operator who uses Calculation Methodology 1 must determine the model input parameters of 40 CFR §98.233(e)(1)(i)-(xi) under normal operating conditions. Wet natural gas composition must be determined using an industry standard method. When using the methodology found in 40 CFR §98.233(e)(5) for desiccant dehydrators, the operator must use the following methodology and equation:~~

~~(1) For dehydrators that use desiccant, the operator shall calculate emissions from the amount of gas vented from the vessel every time the desiccator is depressurized for the desiccant refilling process, using the following equation.~~

~~Desiccant dehydrators covered in paragraph (g) of this section do not have to report emissions under this paragraph.~~

$$E_{s,n} = n(H * D^2 * \pi * P_2 * \%G)/(4 * P_1 * 1{,}000cf/Mcf)$$

~~Where;~~
~~$E_{s,n}$ = Annual natural gas emissions at standard conditions (Mcf).~~
~~n = number of dessicant refillings during the reporting period.~~
~~H = Height of the dehydrator vessel (ft).~~
~~D = Inside diameter of the vessel (ft).~~
~~P_1 = Atmospheric pressure (psia)~~
~~P_2 = Pressure of the gas (psia).~~
~~π = pi (3.1416).~~
~~%G = Percent of packed vessel volume that is gas (expressed as a decimal).~~

~~(2) Both CH_4 and CO_2 volumetric and mass emissions must be calculated from volumetric natural gas emissions using the calculations in paragraphs (s) and (t) of this section.~~

~~(e) *Well Venting For Liquids Unloadings*~~

~~(1) The operator who is subject to the reporting requirements of 40 CFR §98.233(f) must calculate emissions from each well venting for liquids unloading using the methods found in 40 CFR §98.233(f)(2)-(4).~~

~~(f) *Gas Well Venting During Completions and Workovers.*~~

~~The operator who is subject to the reporting requirements in 40 CFR §98.233(g) and/or §98.233(h) must calculate emissions for each well completion and workover using one of the following methods.~~

~~(1) *Calculation Methodology 1:*~~

~~(A) The operator must measure total gas flow with a recording flow meter (analog or digital) installed in the vent line.~~

~~(B) The operator must correct total gas volume vented for the volume of CO_2 or N_2 injected and the volume of gas recovered into a sales lines as follows:~~

$$V_{c/wo} = V_M - V_{CO2/N2)} - SG$$

~~Where:~~
~~$V_{c/wo}$ = Volume of gas vented during the well completion or workover.~~
~~V_M = Volume of vented gas measured during well completion or workover.~~
~~$V_{CO2/N2}$ = Volume of CO_2 or N_2 injected during well completion or workover.~~
~~SG = Volume of gas recovered into a sales pipeline.~~

~~(C) All gas volumes must be corrected to standard temperature and pressure using methods in paragraph (r) of this section.~~

~~(D) The operator must calculate CO_2 and CH_4 mass emissions from gas venting using the methods found in paragraphs (r) and (s) of this section.~~

~~(2) *Calculation Methodology 2:*~~

~~(A) The operator must make a series of measurements of upstream pressure (P_1) and downstream pressure (P_2) across a choke installed in the vent line and upstream gas temperature according to methods in section 95154 during each well completion and well workover. The operator must record this data at a time interval (*e.g.*, every five minutes) suitable to accurately describe both sonic and subsonic flow regimes. Sonic flow is defined as the flow regime where $P_2/P_1 \leq 0.542$. Subsonic flow is defined as the flow regime where $P_2/P_1 > 0.542$. The operator must then calculate flow rate for both sonic and subsonic flow regimes using the following equations:~~

~~1. Sonic flow regime~~

~~a. The operator must calculate average flow rate during sonic flow conditions as follows:~~

$$\cancel{FR_s = 1.27 * 10^5 * A * \sqrt{187.08 * T_u}}$$

~~FR_s = Average flow rate in cubic feet per hour under sonic flow conditions.~~
~~$1.27*10^5$ = Conversion factor from m^3/second to ft^3/hour.~~
~~A = Cross al area of the orifice (m^2).~~
~~187.08 = Constant with units of $m^2/(sec^2*K)$.~~
~~T_u = Upstream gas temperature (degrees Kelvin).~~

~~b. The operator must calculate total gas volume vented during sonic flow conditions as follows:~~

$$\cancel{V_s = T_s * FR_s}$$

~~Where:~~
~~V_s = Volume of gas vented during sonic flow conditions (scf).~~
~~T_s = Total time the specific source associated with the equipment leak emission was operational in the calendar year, in hours.~~
~~FR_s = Average flow rate in cubic feet per hour under sonic flow conditions.~~

~~c. The operator must correct V_s to standard conditions using the methodology in paragraph (r) of this section.~~

~~2. Subsonic flow regime~~

~~a. The operator must calculate instantaneous gas flow rates during subsonic flow conditions as follows:~~

$$\cancel{FR_{i/ss} = 1.27 * 10^5 * A * \sqrt{3430 * T_u[(P_2/P_1)^{1.515} - (P_2/P_1)^{1.758}]}}$$

~~Where:~~

~~$FR_{i/ss}$ = Instantaneous flow rate at time T_i during subsonic flow conditions.~~
~~$1.27*10^5$ = Conversion factor from m^3/second to ft^3/hr.~~
~~A = Cross al area of the orifice (m^2).~~
~~3430 = Constant with units of m^2/(sec*K).~~
~~T_u = Upstream gas temperature (degrees Kelvin).~~
~~P_2 = Downstream pressure (psia).~~
~~P_1 = Upstream pressure (psia).~~

~~b. The operator must determine total gas volume vented during subsonic flow conditions (V_{ss}) as the total volume under the curve of a plot of $FR_{i/ss}$ and Time (T_i) for the time period during which the well was flowing under subsonic conditions.~~

~~c. The operator must sum the vented volumes during sonic and subsonic flow and adjust emissions for the volume of CO_2 or N_2 injected and the volume of gas recovered into a sales lines as follows:~~

$$\cancel{V_{c/wo} = V_s + V_{ss} - V_{\frac{CO2}{N2}} - SG}$$

~~Where:~~

~~$V_{c/wo}$ = Volume of gas vented during well completion or workover (scf).~~
~~V_s = Volume of gas vented during sonic flow conditions (scf).~~
~~V_{ss} = Volume of gas vented during subsonic flow conditions (scf).~~
~~$V_{CO2/N2}$ = Volume of CO_2 or N_2 injected during well completion or workover.~~
~~SG = Volume of gas recovered into a sales pipeline (scf).~~

~~d. The operator must correct all gas volumes to standard conditions using methods in paragraph (r) of this section.~~

~~e. The operator must sum emissions from all well completions and workovers and calculate CO_2 and CH_4 volumetric and mass emissions using the methods in paragraphs (s) and (t) of this section.~~

~~(g) *Transmission storage tanks.* The operator who is subject to the requirements of 40 CFR §98.233(k) must use the calculation methodologies in 40 CFR §98.233(k).~~

~~(h) *Blowdown Vent Stacks.* The operator who is subject to the requirements of 40 CFR §98.233(i) must use the reporting methodologies in 40 CFR §98.233(i).~~

~~(i) *Onshore Production and Processing Storage Tanks.* The operator who is subject to the requirements of 40 CFR §98.233(j) must use the calculation methodologies in 40 CFR §98.233(j).~~

~~(j) *Well Testing Venting and Flaring.* The operator who is subject to the reporting requirements in 40 CFR §98.2333(l) must use the calculation methodologies in 40 CFR §98.233(l).~~

~~(k) *Associated Gas Venting and Flaring.* The operator who is subject to the reporting requirements of 40 CFR §98.233(m) must use the calculation methodology found in 40 CFR §98.233(m).~~

~~(l) *Flare Stacks.* The operator who is subject to the reporting requirements in 40 CFR §98.233(n) must use the calculation methodologies found in 40 CFR §98.233(n).~~

~~(m) *Centrifugal Compressor Venting.*~~

~~(1) The operator must calculate CO_2, CH_4, and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents for all compressors with rated horsepower of 250hp or greater using the methodologies found in 40 CFR §98.233(o)(1)-(6) and (8)-(9).~~

~~(2) The operator must calculate CO_2, CH_4, and N_2O (when flared) emissions for all centrifugal compressors with rated horsepower less than 250hp using the methodologies found in 40 CFR §98.233(o)(7).~~

~~(n) *Reciprocating Compressor Rod Packing Venting.* The operator must calculate annual CH_4, CO_2, and N_2O (when flared) emissions from each reciprocating compressor rod packing venting for each applicable operational mode for all compressors with a rated horse power of 250hp or greater using the methodologies found in 40 CFR §98.233(p)(1)-(8) and (10). The operator must calculate CO_2, CH_4, and N_2O (when flared) emissions from reciprocating compressor rod packing venting for each applicable operational mode for all reciprocating compressors with a rated horse power less than 250hp using the methodologies found in 40 CFR §98.233(p)(9).~~

~~(o) *Leak Detection and Leaker Emission Factors.* The operator who is subject to the reporting requirements found in 40 CFR §98.233(q) must use the calculation methodologies found in 40 CFR §98.233(q).~~

~~(p) *Population Count and Emission Factors.* The operator who is subject to the reporting requirements found in 40 CFR §98.233(r) must use the calculation methodologies found in 40 CFR §98.233(r).~~

~~(q) *Offshore Petroleum and Natural Gas Production Facilities.* The operator who is subject to the reporting requirements found in 40 CFR §98.233(s) must use the calculation methodologies found in 40 CFR §98.233(s).~~

~~(r) *Volumetric Emissions.* The operator must use the calculation methodologies found in 40 CFR §98.233(t) when calculating volumetric emissions at standard conditions using the calculation methodologies found in 40 CFR §98.233(t).~~

~~(s) *GHG Volumetric Emissions.* The operator must calculate GHG volumetric emissions at standard conditions as specified in 40 CFR §98.233(u).~~

~~(t) *GHG Mass Emissions.* The operator must calculate GHG mass emissions using the following equation:~~

$$\cancel{Mass_{s,i} = E_{s,i} * \rho_i * 10^{-3}}$$

~~Where:~~

~~$Mass_{s,i}$ = GHG i (either CO_2 or CH_4) mass emissions at standard conditions in metric tons.~~

~~$E_{s,i}$ = GHG i (either CO_2 or CH_4) volumetric emissions at standard conditions, in cubic feet.~~

~~P = Density of GHG i. Use 0.0538 kg/ft^3 for CO_2 and N_2O, and 0.0196 kg/ft^3 for CH_4 at 68°F and 14.7 psia or 0.0530 kg/ft^3 for CO_2 and N_2O, and 0.0193 kg/ft^3 for CH_4 at 60°F and 14.7 psia.~~

~~(u) *EOR Injection Pump Blowdown.* The operator who is subject to the reporting requirements in 40 CFR §98.233(w) must use the calculation methodologies found in 40 CFR §98.233(w).~~

~~(w) *Stationary and Portable Equipment Combustion Emissions.* The operator must use the methods in 95115 to report the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment as defined in 40 CFR §98.232(c)(22).~~

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§95154. Monitoring and QA/QC Requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable and as specified in this section. Offshore petroleum and natural gas production facilities must adhere to the monitoring and QA/QC requirements as set forth in 30 CFR §250 (July 1, 2011), which is hereby incorporated by reference.

(a) ~~The operator must conform with the monitoring and QA/QC requirements of 40 CFR §98.234.~~Facility operators must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in sections 95153(i), (m), (n) and (o) that occur during a calendar year, except as provided in paragraph (a)(4) of this section.

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR Part 60, subarticle A, §60.18 of the *Alternative work practice for monitoring equipment leaks*, §60.18(i)(1)(i); §60.18(i)(2)(i) except that the monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR Part 60, subarticle A, Table 1: *Detection Sensitivity Levels*; §60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and §60.18(i)(2)(iv) and (v); §60.18(i)(3); §60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records (July 1, 2011, which is hereby incorporated by reference). Any emissions detected by the optical gas imagining instrument is a leak unless screened with Method 21 (40 CFR Part 60, appendix A-7 (July 1, 2011), which is hereby incorporated by reference) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, facility operators must operate the optical gas imagining instrument to image the source types required by this subarticle in accordance with the instrument manufacturer's operating parameters. Unless using methods in paragraph (a)(2) of this section, an optical gas imagining instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than two meters above a support surface.

(2) *Method 21.* Use the equipment leak detection methods in 40 CFR Part 60, appendix A-7, Method 21 (July 1, 2011). If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR Part 60, are not exempt from this subarticle. Owners or operators must use alternative leak detection devices as described in paragraph (a)(1) or (a)(2) of this section to monitor inaccessible equipment leaks or vented emissions.

(3) *Infrared laser beam illuminated instrument.* Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated

a leak. In addition, the facility operator must operate the infrared laser beam illuminated instrument to detect the source types required by this subarticle in accordance with the instrument manufacturer's operating instructions.

(4) *Optical gas imaging instrument.* 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 a support surface.

(5) *Acoustic leak detection device.* Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, the facility operator must operate the acoustic leak detection device to monitor the source valves required by this subarticle in accordance with the instrument manufacturer's operating parameters. Acoustic stethoscope type devices designed to detect through valve leakage when put in contact with the valve body and that provide an audible leak signal but do not calculate a leak rate can be used to identify non-leakers with subsequent measurement required to calculate the rate if through-valve leakage is identified. Leaks are reported if a leak rate of 3.1 scf per hour or greater is measured. In addition, the facility operator must operate the acoustic leak detection device to monitor the source valves required by this subarticle in accordance with the instrument manufacturer's operating parameters.

(b) The operator must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in section 95153 according to the procedures in section 95103(k) and the procedures in paragraph (b) of this section. Pursuant to section 95109 of this article, the facility operator may use an appropriate standard method published by a consensus-based standards organization if such a method exists or use an industry standard practice.

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and below the maximum temperature specified by the vent bag manufacturer such that the vent bag is safe to handle. The bag opening must be of sufficient size that the entire emission can be tightly encompassed for measurement till the bag is completely filled.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in section 95153(r).
(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in sections 95153(s) and (t).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer's operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak without creating backpressure on the source.
(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.
(3) Estimate natural gas volumetric emissions at standard conditions using calculations in section 95153(r). Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in sections 95153(s) and (t).
(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples by following manufacturer's instructions for calibration.

(e) Peng-Robinson Equation of State means the equation of state defined by Equation 38 of this section.

$$p = \frac{RT}{(V_m - b)} - a\alpha/(V_m^2 + 2bV_m - b^2) \qquad \text{(Eq. 38)}$$

Where:

p = Absolute pressure.
R = Universal gas constant
T = Absolute temperature.
V_m = Molar volume.

$$a = 0.45724R^2T_c^2/p_c$$
$$b = 0.7780RT_c/p_c$$
$$\alpha = \left(1 + (0.37464 + 1.54226\omega - 0.26992\omega^2)(1 - \sqrt{T/T_c})\right)^2$$

Where:

ω = Acentric factor of the species.
T_c = Critical temperature.
P_c = Critical pressure.

(f) *Special reporting provisions: best available monitoring methods.* Best available monitoring methods will be allowed for the reporting of 2012 data as described in paragraphs (1)-(4). Beginning with collection of data on January 1, 2013, best available monitoring methods will no longer be allowed.

(1) ARB will allow owners or operators to use best available monitoring methods for certain parameters in section 95153 as specified in paragraphs (f)(2), (f)(3), and (f)(4) of this section. Best available monitoring methods means any of the following methods specified in paragraph (f)(1) of this section:

(A) Monitoring methods currently used by the facility that do not meet the specifications of this subarticle.

(B) Supplier data.

(C) Engineering calculations.

(D) Other company records.

(2) Operators may use best available monitoring methods for any well-related data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subarticle, and only where required measurements cannot be duplicated due to technical limitations after December 31, 2012. These well-related sources are:

(A) Gas well venting during well completions and workovers as specified in section 95153(f).

(B) Well testing venting and flaring as specified in section 95153(e).

(3) Operators may use best available monitoring methods for activity data as listed below that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subarticle, specifically for events that generate data that can be collected in 2012 and cannot be duplicated after December 31, 2012. These sources are:

(A) Cumulative hours of venting, days, or times of operation in sections 95153 (d), (e), (f), (j), (m), (n), (o), and (p).

(B) Number of blowdowns, completions, workovers, or other events in sections 95153(e), (f), (g), and (u).

(C) Cumulative volume produced, volume input or output, or volume of fuel used in sections 95153(c), (d), (h), (i), (j), (k), (l), and (y).

(4) Operators may use best available monitoring methods for sources requiring leak detection and/or measurement. These sources include:

(A) Reciprocating compressor rod packing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in sections 95152 (d)(6), (e)(7), (f)(6), (g)(4), and (h)(4).

(B) Centrifugal compressor wet seal oil degassing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and

<u>export equipment as specified in sections 95152(d)(5), (e)(6), (f)(5), (g)(3), and (h)(3).</u>
<u>(C) Acid gas removal vent stacks in onshore petroleum and natural gas production and onshore natural gas processing as specified in sections 95152(c)(3) and (d)(4).</u>
<u>(D) Equipment leak emissions from valves, connectors, open ended lines, pressure relief valves, block valves, control valves, compressor blowdown valves, orifice meters, other meters, regulators, vapor recovery compressors, centrifugal compressor dry seals, and/or other equipment leaks in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, and natural gas distribution as specified in sections 95152(c)(17) (d)(7), (e)(8), (f)(7), (g)(5), (h)(5), and (i)(1).</u>

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§95155. Procedures for Estimating Missing Data.

(a) A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, the operator must repeat the estimation or measurement activity for those sources within the measurement period. In cases where repeat sampling and/or analysis cannot be completed, the operator must follow the missing data substitution procedures for 2013 and later emissions data reports. ~~For the 2012 emissions data report, the operator must follow the requirements of 40 CFR §98.235.~~

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NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§ 95156. <u>Additional</u> Data Reporting Requirements.

Operators must conform with the data reporting requirements in ~~40 CFR §98.236~~ <u>section 95157</u> except as specified below.

(a) In addition to the data required by <u>section 95157</u>,~~40 CFR §98.236 (a)-(c),~~ the operator of an onshore <u>and offshore</u> petroleum and natural gas production facility must report the following data disaggregated within the basin by each facility that lies within contiguous property boundaries:

(1) CO_2e emissions, including CO_2, CH_4, and N_2O as applicable for the source types specified in section 95152(c);
(2) For combustion sources for which emissions are reported, fuel use by fuel type;
(3) For cogeneration sources:

(A) Total thermal output (MMBtu) and the portion of CO_2e emissions associated with this output;
(B) Net electricity generation (MWh) and the portion of CO_2e emissions associated with this generation;
(C) Amount of electricity generation (MWh) not consumed within the facility (i.e., exported offsite or to another facility owner/operator) and the portion of CO_2e emissions associated with this generation;

(4) For steam generator sources:

(A) Total thermal output (MMBtu) and the CO_2e emissions associated with this output;
(B) Thermal output (MMBtu) not utilized within the facility (i.e., exported offsite or to another facility owner/operator) and the CO_2e emissions associated with this output;

(5) For electricity generation sources not included in section 95156(a)(3):

(A) Net electricity generation (MWh) and the CO_2e emissions associated with this generation;
(B) Amount of electricity generation (MWh) not consumed within the facility (i.e., exported offsite or to another facility owner/operator) and the portion of CO_2e emissions associated with this generation;

(6) Total steam (MMBtu) utilized but not generated at the facility and the CO_2e emissions associated with this output, if known;
~~(3)~~(7) Barrels of crude oil produced using thermal enhanced oil recovery, ~~and the portion of CO2e emissions associated with this production~~;
~~(4)~~(8) Barrels of crude oil produced using methods other than thermal enhanced oil recovery, ~~and the portion of CO2e emissions associated with this production.~~;
(9) MMBtu of associated gas produced using thermal enhanced oil recovery;
(10) MMBtu of associated gas produced using methods other than thermal enhanced oil recovery.
(11) The operator of an onshore petroleum and natural gas production facility may voluntarily report the annual product data information in sections 95156(a)(9)-(10) for calendar years 2011 and 2012. If the operator chooses to report the 2011 and 2012 product data, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014

and any subsequent year, the operator must report and verify the annual product data listed in section 95156(a)(9)-(10).

~~(b) In lieu of the requirements of 40 CFR §98.236(c)(19), the operator of an onshore petroleum and natural gas production facility must submit combustion emissions data according to the requirements of 40 CFR §98.36.~~

(b) For dry gas production, the operator of an onshore petroleum and natural gas production facility may voluntarily report its annual volume of dry gas produced (Mscf) for calendar years 2011 and 2012. If the operator chooses to report the 2011 and 2012 dry gas produced, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, the operator must report and verify the volume of dry natural gas produced (Mscf).

(c) For underground natural gas storage, the operator must report the volume of natural gas extracted (Mscf).

(d) The operator of a natural gas liquid fractionating facility or a natural gas processing facility must report the annual production of the following natural gas liquids in barrels corrected to 60 degrees Fahrenheit:

(1) Ethane
(2) Ethylene
(3) Propane
(4) Propylene
(5) Butane
(6) Butylene
(7) Isobutane
(8) Isobutylene
(9) Pentanes plus
(10) Natural gasoline
(11) Liquefied petroleum gas
(12) Bulk natural gas liquids not included in 95156(d)(1)-(11)

(e) The operator of a natural gas liquid fractionating facility may voluntarily report the annual product data information in sections 95156(d)(1)-(12) for calendar years 2011 and 2012. If the operator chooses to report the 2011 and 2012 product data, then they must submit the data to ARB by April 10, 2013 and follow the verification requirements of this article. For emissions data reports submitted in 2014 and any subsequent year, the operator must report and verify the annual product data listed in section 95156(d)(1)-(12).

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§95157. Activity Data Reporting Requirements.

In addition to the information required by section 95103, each annual report must contain reported emissions and related information as specified in this section.

(a) Report annual emissions in metric tons per year for each GHG separately for each of the industry segments listed in paragraphs (a)(1) through (8) of this section:

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

(b) For offshore petroleum and natural gas production, report emissions of CH_4, CO_2, and N_2O as applicable to the source type (in metric tons per year at standard conditions) individually for all of the emissions source types listed in the most recent BOEM study.

(c) Report the information listed in this paragraph for each applicable source type in metric tons for each GHG type. If a facility operates under more than one industry segment, each piece of equipment should be reported under the unit's respective majority use segment. When a source type listed under this paragraph routes gas to flare, separately report the emissions that were vented directly to the atmosphere without flaring, and the emissions that resulted from flaring of the gas. Both the vented and flared emissions will be reported under respective source types and not under flare source type.

(1) For natural gas pneumatic devices (refer to Equations 1 and 2 of section 95153), report the following:

(A) Actual count and estimated count separately of natural gas pneumatic high bleed devices, as applicable.
(B) Actual count and estimated count separately of natural gas low bleed devices, as applicable.
(C) Actual count and estimated count separately of natural gas pneumatic intermittent bleed devices, as applicable.
(D) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, for each of the following pieces of equipment: high bleed pneumatic devices; intermittent bleed pneumatic devices; low bleed pneumatic devices.

(2) For natural gas driven pneumatic pumps (refer to Equation 1 and 2 of section 95153), report the following:

(A) Count of natural gas driven pneumatic pumps.
(B) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, for all natural gas driven pneumatic pumps combined.

(3) For each acid gas removal unit (refer to Equation 3 and Equation 4 of section 95153), report the following:

(A) Total throughput of the acid gas removal unit using a meter or engineering estimate based on process knowledge or best available data in million cubic feet per year.
(B) For Calculation Methodology 1 and Calculation Methodology 2 of section 95153(c), annual fraction of CO_2 content in the vent from acid gas removal unit (refer to section 95153(c)(6)).
(C) For Calculation Methodology 3 of section 95153(c), annual average volume fraction of CO_2 content of natural gas into and out of the acid gas removal unit (refer to section 95153(c)(6)).
(D) Report the annual quantity of CO_2, expressed in metric tons that was recovered from the AGR unit and transferred outside the facility, under section 95153.
(E) Report annual CO_2 emissions for the AGR unit, expressed in metric tons.
(F) For the onshore natural gas processing industry segment only, report a unique name or ID number for the AGR unit.
(G) An indication of which methodology was used for the AGR unit.

(4) For dehydrators, report the following:

(A) For each Glycol dehydrator (refer to section 95153(d)(1)), report the following:

1. Glycol dehydrator feed natural gas flow rate in MMscfd, determined by engineering estimate based on best available data.
2. Glycol dehydrator absorbent circulation pump type.
3. Whether stripper gas is used in glycol dehydrator.
4. Whether a flash tank separator is used in glycol dehydrator.
5. Type of absorbent.
6. Total time the glycol dehydrator is operating in hours.
7. Temperature, in degrees Fahrenheit and pressure, in psig, of the wet natural gas.
8. Concentration of CH_4 and CO_2 in wet natural gas.

9. What vent gas controls are used (refer to sections 95153(d)(3) and (d)(4)).
10. For each glycol dehydrator, report annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons for each gas.
11. For each glycol dehydrator, report annual CO_2, CH_4, and N_2O emissions that resulted from flaring process gas from the dehydrator, expressed in metric tons for each gas.
12. For the onshore natural gas processing industry segment only, report a unique name or ID number for (each) glycol dehydrator.

(B) For absorbent desiccant dehydrators (refer to Equation 5 of section 95153), report the following:

1. Count of desiccant dehydrators.
2. Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, for all absorbent desiccant dehydrators combined.

(5) For well venting for liquids unloading, report the following:

(A) For Calculation Methodology 1 (refer to Equation 6 of section 95153(e)), report the following:

1. Count of wells vented to the atmosphere for liquids unloading.
2. Count of plunger lifts. Whether the well had a plunger lift (yes/no).
3. Cumulative number of unloadings vented to the atmosphere.
4. Internal casing diameter or internal tubing diameter in inches, where applicable, and well depth of each well, in feet.
5. Casing pressure, in psia, of each well that does not have a plunger lift.
6. Tubing pressure, in psia, of each well that has a plunger lift.
7. Report annual CO_2 and CH_4 emissions, expressed in metric tons for each gas.

(B) For Calculation Methodologies 2 (refer to Equation 7 of section 95153(e)), report the following for each basin:

1. Count of wells vented to the atmosphere for liquids unloading.
2. Count of plunger lifts.
3. Cumulative number of unloadings vented to the atmosphere.
4. Average internal casing diameter, in inches, of each well, where applicable.
5. Report annual CO_2 and CH_4 emissions, expressed in metric tons for each GHG gas.

(6) For well completions and workovers, report the following for each basin category:

(A) Total count of completions in calendar year.
(B) Total count of workovers in calendar year.
(C) Report number of completions employing purposely designed equipment that separates natural gas from the backflow and the amount of natural gas, in standard cubic feet, recovered using engineering estimate based on best available data.
(D) Report number of workovers employing purposely designed equipment that's separates natural gas from the backflow and the amount of natural gas recovered using engineering estimate based on best available data.
(E) Annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons for each gas.
(F) Annual CO_2, CH_4, and N_2O emissions that resulted from flares, expressed in metric tons for each gas.

(7) For each equipment and pipeline blowdown event (refer to Equation 13 and Equation 14 of section 95153(g)), report the following:

(A) For each unique physical volume that is blowdown more than once during the calendar year, report the following:

1. Total number of blowdowns for each unique physical volume, expressed in metric tons for each gas.
2. Annual CO_2 and CH_4 emissions for each unique physical blowdown volume, expressed in metric tons for each gas.
3. A unique name or ID number for the unique physical volume.

(B) For all unique volumes that are blow down once during the calendar year, report the following:

1. Total number of blowdowns for all unique physical volumes in the calendar year.
2. Annual CO_2 and CH_4 emissions from all unique physical volumes as an aggregate per facility, expressed in metric tons for each gas.

(8) For gas emitted from produced oil sent to atmospheric tanks:

(A) If a wellhead separator dump valve is functioning improperly during the calendar year (refer to section 95153 (i)), report the following:

1. Count of wellhead separators that dump valve factor is applied.

2. Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons for each gas, at the ~~sub-~~basin level for improperly functioning dump valves.

(9) For transmission tank emissions identified using optical gas imagining instrument pursuant to section 95154(a) (refer to section 95153(i)), or acoustic leak detection of scrubber dump valves, report the following:

(A) For each vent stack, report annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons for each gas.
(B) For each transmission storage tank, report annual CO_2, CH_4 and N_2O emissions that resulted from flaring process gas from the transmission storage tank, expressed in metric tons for each gas.
(C) A unique name or ID number for the vent stack monitored according to section 95153(i).

(10) For well testing venting and flaring (refer to Equation 15 or 16 of section 95153(j)), report the following:

(A) Number of wells tested per basin in calendar year.
(B) Average gas to oil ratio for each basin.
(C) Average number of days the well is tested in a basin.
(D) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, emissions from well testing venting.
(E) Report annual CO_2, CH_4 and N_2O emissions at the facility level, expressed in metric tons for each gas, emissions from well testing flaring.

(11) For associated natural gas venting and flaring (refer to Equation 17 of section 95153), report the following for each basin:

(A) Number of wells venting or flaring associated natural gas in a calendar year.
(B) Average gas to oil ratio for each basin.
(C) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons for each gas, emission s from associated natural gas venting.
(D) Report annual CO_2, CH_4 and N_2O emissions at the facility level, expressed in metric tons for each gas, emissions from associated natural gas flaring.

(12) For flare stacks (refer to Equation 18, 19, and 20 of section 95153(l)), report the following for each flare:

(A) Whether flare has a continuous flow monitor.
(B) Volume of gas sent to flare in cubic feet per year.
(C) Percent of gas sent to un-lit flare determined by engineering estimate and process knowledge based on best available data and operating records.
(D) Whether flare has a continuous gas analyzer.
(E) Flare combustion efficiency.
(F) Report uncombusted CH_4 emissions, in metric tons (refer to Equation 18 of section 95153).
(G) Report uncombusted CO_2 emissions, in metric tons (refer to Equation 19 of section 95153).
(H) Report combusted CO_2 emissions, in metric tons (refer to Equation 20 of section 95153).
(I) Report N_2O emissions, in metric tons.
(J) For the natural gas processing industry segment, a unique name or ID number for the flare stack.
(K) In the case that a CEMS is used to measure CO_2 emissions for the flare stack, indicate that a CEMS was used in the annual report and report the combusted CO_2 and uncombusted CO_2 as a combined number.

(13) For each centrifugal compressor:

(A) For compressors with wet seals in operational mode (refer to Equation 21 and 22 of section 95153(m)), report the following for each degassing vent:

1. Number of wets seals connected to the degassing vent.
2. Fraction of vent gas recovered for fuel or sales or flared.
3. Annual throughput in million scf, use an engineering calculation based on best available data.
4. Type of meters used for making measurements.
5. Total time the compressor is operating in hours.
6. Report seal oil degassing vent emissions for compressors measured (refer to Equation 21 of section 95153) and for compressors not measured (refer to Equation 22 of section 95153).

(B) For wet and dry seal centrifugal compressors in operating mode, (refer to Equation 21 and 22 of section 95153(m)), report the following:

1. Total time in hours the compressor is in operating mode.
2. Report blowdown vent emissions when in operating mode (refer to Equation 21 and 22 of section 95153).

(C) For wet and dry seal centrifugal compressors in not operating, depressurized mode (refer to Equations 21 and 22 of section 95153(m)), report the following:
   1. Total time in hours the compressor is in shutdown, depressurized mode.
   2. Report the isolation valve leakage emissions in not operating, depressurized mode in cubic feet per hour (refer to Equations 21 and 22 of section 95153).

(D) Report total annual compressor emissions from all modes of operation.

(14) For reciprocating compressors:

(A) For reciprocating compressors rod packing emissions with or without a vent in operating mode, report the following:

   1. Annual throughput in million scf, use an engineering calculation based on best available data.
   2. Total time in hours the reciprocating compressor is in operating mode.
   3. Report rod packing emissions for compressors measured (refer to Equation 23 of section 95153).

(B) For reciprocating compressors blowdown vents not manifold to rod packing vents, in operating and standby pressurized mode, report the following:

   1. Total time in hours the compressor is in standby, pressurized mode.
   2. Report blowdown vent emissions when in operating and standby modes.

(C) For reciprocating compressors in not operating, depressurized mode report the following:
   1. Total time the compressor is in not operating depressurized mode.
   2. Facility operator emission factor for isolation valve emissions in not operating mode, depressurized mode in cubic feet per hour.
   3. Report the isolation valve leakage emissions in not operating, depressurized mode.

(D) Report total annual compressor emissions from all modes of operation.
(E) For reciprocating compressors in onshore petroleum and natural gas production report the following:

   1. Count of compressors.
   2. Report emissions collectively.

(15) For each component type (major equipment type for onshore production) that uses emission factors for estimating emissions (refer to sections 95153(o) and (p).

(A) For equipment leaks found in each leak survey (refer to section 95153(o)), report the following:

1. Total count of leaks found in each complete survey listed by date of survey and each component type for which there is a leak emission factor in Tables 2, 3, 4, 5, 6, and 7 of Appendix A.
2. For onshore natural gas processing, range of concentrations of CH_4 and CO_2.
3. Annual CO_2 and CH_4 emissions, in metric tons for each gas by component type.

(B) For equipment leaks calculated using population counts and factors (refer to section 95153(p)), report the following:

1. For source categories listed in sections 95150(a)(4), (a)(5), (a)(6), and (a)(7), total count for each component type in Tables 2, 3, 4, 5, and 6 of Appendix A for which there is a population emission factor, listed by major heading and component type.
2. For onshore production (refer to section 95150 (a)(2)), total count for each type of major equipment in Table 1B and Table 1C of Appendix A, by facility.
3. Annual CO_2 and CH_4 emissions, in metric tons for each gas by component type.

(16) For local distribution companies, report the following:

(A) Total number of above grade T-D transfer stations in the facility.
(B) Number of years over which all T-D transfer stations will be monitored at least once.
(C) Number of T-D stations monitored in calendar year.
(D) Total number of below grade T-D transfer stations in the facility.
(E) Total number of above grade metering-regulating stations (this count will include above grade T-D transfer stations) in the facility.
(F) Total number of below grade metering-regulating stations (this count will include below grade T-D transfer stations) in the facility.
(G) Leak factor for meter/regulator run developed in Equation 28 of section 95153.
(H) Number of miles of unprotected steel distribution mains.
(I) Number of miles of protected steel distribution mains.
(J) Number of miles of plastic distribution mains.

(K) Number of miles of cast iron distribution mains.
(L) Number of unprotected steel distribution services.
(M) Number of protected steel distribution services.
(N) Number of plastic distribution services.
(O) Number of copper distribution services.
(P) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all below grade T-D transfer stations combined.
(Q) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all above grade metering-regulating stations (including T-D transfer stations) combined.
(R) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all below grade metering-regulating stations (including T-D transfer stations) combined.
(S) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all distribution mains combined.
(T) Annual CO_2 and CH_4 emissions, in metric tons for each gas, from all distribution services combined.

(17) For each EOR injection pump blowdown (refer to Equation 33 of section 95153), report the following:

(A) Pump capacity, in barrels per day.
(B) Volume of critical phase gas between isolation valves.
(C) Number of blowdowns per year.
(D) Critical phase EOR injection gas density.
(E) For each EOR pump, report annual CO_2 and CH_4 emissions, expressed in metric tons for each gas.

(18) For EOR hydrocarbon liquids dissolved CO_2 (refer to section 95153(v)), report the following:

(A) Volume of crude oil produced in barrels per year.
(B) Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.
(C) Report annual CO_2 emissions at the basin level.

(19) For onshore petroleum and natural gas production and natural gas distribution combustion emissions, report the following:

(A) Cumulative number of external fuel combustion units with a rated heat capacity equal to or less than 5 MMBtu/hr, by type of unit.
(B) Cumulative number of external fuel combustion units with a rated heat capacity larger than 5 MMBtu/hr, by type of unit.

(C) Report annual CO_2, CH_4, and N_2O emissions from external fuel combustion units with a rated heat capacity larger than 5 MMBtu/hr, expressed in metric tons for each gas, by type of unit.

(D) Cumulative volume of fuel combusted in external fuel combustion units with a rated heat capacity larger than 5 MMBtu/hr, by type of unit.

(E) Cumulative number of internal fuel combustion units, not compressor-drivers, with a rated heat capacity equal to or less than 1 MMBtu/hr or 130 horsepower, by type of unit.

(F) Report annual CO_2, CH_4 and N_2O emissions from external fuel combustion units with a rated heat capacity larger than 5 MMBtu/hr, expressed in metric tons for each gas, by type of unit.

(G) Cumulative volume of fuel combusted in internal combustion units with a rated heat capacity larger than 1 MMBtu/hr or 130 horsepower, by fuel type.

(d) Report annual throughput as determined by engineering estimate based on best available data for each industry segment listed in paragraphs (a)(1) through (a)(8) of this section.

(e) For onshore petroleum and natural gas production, report the best available estimate of API gravity, best available estimate of gas to oil ratio, and best available estimate of average low pressure separator pressure for each oil basin category.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4, and 41511, Health and Safety Code. Reference: Sections 38530, 39600, and 41511, Health and Safety Code.

§95158~~7~~. Records That Must Be Retained.

The operator shall follow the document retention requirements of section 95105 of this article~~, in addition to those of 40 CFR §98.237~~.

NOTE: Authority cited: Sections 38510, 38530, 39600, 39601, 39607, 39607.4 and 41511, Health and Safety Code. Reference: Sections 38530, 39600 and 41511, Health and Safety Code.

Appendix A

to the Regulation for the Mandatory Reporting
of Greenhouse Gas Emissions

Emission Factors and Calculation Data for Petroleum and Natural Gas Systems Reporting

Table 1A
Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production

Onshore petroleum and natural gas production	Emission factor (scf/hour/ component)
Western U.S. **Population Emission Factors All components, Gas Service:[1]**	
Valve	0.121
Connector	0.017
Open-ended line	0.031
Pressure relief valve	0.193
Low Continuous Bleed Pneumatic Device Vents[2]	1.39
High Continuous Bleed Pneumatic Device Vents[2]	37.3
Intermittent Bleed Pneumatic Device Vents[2]	13.5
Pneumatic Pumps[3]	13.3
Population Emission Factors – All Components, Light Crude Service:[4]	
Valve	0.05
Flange	0.003
Connector	0.007
Open-ended Line	0.05
Pump	0.01
Other[5]	0.30
Population Emission Factors – All Components, Heavy Crude Service:[6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other[5]	0.003

[1] For multi-phase flow that includes gas, use the gas service emissions factors.
[2] Emissions factor is in units of "scf/hour/device."
[3] Emission Factor is in units of "scf/hour/pump."
[4] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."
[5] "Other" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.
[6] Hydrocarbon liquids less than 20°API are considered "heavy crude."

Table 1B
Default Average Component Counts for Major Onshore Natural Gas Production Equipment

Major equipment	Valves	Connectors	Open-ended lines	Pressure relief valves
Western U.S.				
Wellheads	11	36	1	0
Separators	34	106	6	2
Meters/piping	14	51	1	1
Compressors	73	179	3	4
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2

Table 1C
Default Average Component Counts for Major Crude Oil Production Equipment

Major equipment	Valves	Flanges	Connectors	Open-ended lines	Other components
Western U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0

Table 2
Default Total Hydrocarbon Emission Factors for Onshore Natural Gas Processing

Onshore natural gas processing	Emission Factor (scf/hour/component)
Leaker Emission Factors – Compressor Components, Gas Service	
Valve[1]	14.84
Connector	5.59
Open-Ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33
Leaker Emission Factors – Non-Compressor Components, Gas Service	
Valve[1]	6.42
Connector	5.71
Open-Ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93

[1] Valves include control valves, block valves and regulator valves.

Table 3
Default Total Hydrocarbon Emission factors for Onshore Natural Gas Transmission Compression

Onshore Natural Gas Transmission compression	Emission Factor (scf/hour/component)
Leaker Emission Factors – Compressor Components, Gas Service	
Valve[1]	14.84
Connector	5.59
Open-Ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33
Leaker Emission Factors – Non-Compressor Components, Gas Service	
Valve[1]	6.42
Connector	5.71
Open-Ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93
Population Emission Factors – Gas Service	
Low Continuous Bleed Pneumatic Device Vents[2]	1.37
High Continuous Bleed Pneumatic Device Vents[2]	18.20
Intermittent Bleed Pneumatic Device Vents[2]	2.35

[1] Valves include control valves, block valves, and regulator valves.
[2] Emission Factor is in units of "scf/hour/component."

Table 4
Default Total Hydrocarbon Emission Factors for Underground Natural Gas Storage

Underground natural gas storage	Emission Factor (scf/hour/component)
Leaker Emission Factors – Storage Station, Gas Service	
Valve[1]	14.84
Connector	5.659
Open-Ended Line	17.27
Pressure Relief valve	39.66
Meter	19.33
Population Emission Factors – Storage Wellheads, Gas Service	
Connector	0.01
Valve[1]	0.1
Pressure Relief Valve	0.17
Open Ended Line	0.03
Population Emission Factor – Other Components, Gas Service	
Low Continuous Bleed Pneumatic Device Vents[2]	1.37
High Continuous Bleed Pneumatic Device Vents[2]	18.20
Intermittent Bleed Pneumatic Device Vents[2]	2.35

[1] Valves include control valves, block valves and regulator valves.
[2] Emission Factor is in units of "scf/hour/device.

Table 5
Default Methane Emission Factors for Liquefied Natural Gas (LNG) Storage

LNG Storage	Emission Factor (scf/hour/component)
Leaker Emission Factors – LNG storage Components, Gas and Liquids Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other[1]	1.77
Population Emission Factors – LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor[2]	4.17

[1] "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.
[2] Emission Factor is in units of "scf/hour/compressor."

Appendix A-6

Table 6
Default Methane Emission Factors for LNG Import and Export Equipment

LNG import and export equipment	Emission Factor (scf/hour/component)
Leaker Emission Factors – LNG Terminals Components, Gas and Liquid Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other[1]	1.77
Population Emission Factors – LNG Terminal Compressor, Gas Service	
Vapor Recovery Compressor[2]	4.17

[1] "other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.
[2] Emission Factor is in units of "scf/hour/compressor."

Table 7
Default Methane Emission Factors for Natural Gas Distribution

Natural gas distribution	Emission Factor (scf/hour/component)
Leaker Emission Factors – Above Grade M&R at City Gate Stations[1] Components	
Connector	1.69
Block Valve	0.557
Control Valve	9.34
Pressure Relief Valve	0.27
Orifice Meter	0.212
Regulator	0.772
Open-ended Line	26.131
Population Emission Factors – Below Grade M&R[2] Components, Gas Service	
Below Grade M&R Station, Inlet Pressure >300 psig	1.30
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	0.20
Below Grade M&R Station, Inlet Pressure <100 psig	0.10
Population emission Factors – Distribution Mains, Gas Service[4]	
Unprotected steel	12.58
Protected Steel	0.35
Plastic	1.13
Cast Iron	27.25
Population Emission Factors – Distribution Services, Gas Service[5]	
Unprotected Steel	0.19
Protected Steel	0.02
Plastic	0.001
Copper	0.03

[1] City gate stations at custody transfer and excluding customer meters.
[2] Excluding customer meters.
[3] Emission Factor is in units of "scf/hour/station."
[4] Emission Factor is in units of "scf/hour/mile."
[5] Emission factor is in units of "scf/hour/number of services."

ATTACHMENT B

PROPOSED REGULATION ORDER

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

NOTE: Changes to the regulation are shown in underline; deletions from the regulation are shown in ~~strikeout~~. "***" indicates that sections of regulation not printed are not changed.

Subchapter 10 Climate Change, Article 5, Section 95802 is amended to read as follows:

Article 5: CALIFORNIA CAP ON GREENHOUSE GAS EMISSIONS AND MARKET-BASED COMPLIANCE MECHANISMS

§ 95802. Definitions.

(a) Definitions. For the purposes of this article, the following definitions shall apply:

*** [No changes were made to subsections (1) through (13).]

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

*** [No changes were made to subsection (15).]

(16) "Associated Gas" or "Produced Gas" means a natural gas that is produced ~~from gas wells or gas produced~~ in association with the production of crude oil.

*** [No changes were made to subsections (17) through (49).]

(50) "Cogeneration" means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy. Cogeneration must involve onsite generation of electricity and useful thermal energy and some form of waste heat recovery. Some examples of cogeneration include: (a) a gas turbine or reciprocating engine generating electricity by combusting fuel, which then uses a heat recovery unit to capture useful heat from the exhaust stream of the turbine or engine; (b) Steam turbines generating electricity as a byproduct of steam generation through a fired boiler; (c) Cogeneration systems in which the fuel input is first applied to a thermal process such as a furnace and at least some of the heat rejected from the process is then used for power production. For the purposes of this article, a combined-cycle power generation unit, where none of the generated thermal energy is used for industrial, commercial, or heating and cooling purposes (these purposes exclude any thermal energy utilization that is either in support of or a part of the electricity generation system), is not considered a cogeneration unit.

*** [No changes were made to subsections (51) through (86).]

(87) "Electricity Importers" ~~are marketers and retail providers that~~ deliver imported electricity. For electricity that is scheduled with a NERC e-Tag to a final point of delivery inside the state of California~~delivered between balancing authority areas~~, the electricity importer is identified on the NERC e-Tag as the purchasing-selling entity (PSE) on the last segment of the tag's physical path with the point of receipt located outside the state of California and the point of delivery located inside the state of California. For facilities physically located outside the state of California with the first point of interconnection to a California balancing authority's transmission and distribution system when the electricity is not scheduled on a NERC e-Tag, the importer is the facility operator or scheduling coordinator. Federal and state agencies are subject to

the regulatory authority of ARB under this article and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and California Department of Water Resources (DWR).

*** [No changes were made to subsections (88) through (94).]

(95) "Enterer" means an entity that imports into California motor vehicle fuel, diesel fuel, fuel ethanol, biodiesel, non-exempt biomass-derived fuel or renewable fuel and who is the importer of record under federal customs law or the owner of fuel upon import into California if the fuel is not subject to federal customs law. <u>Only enterers that import the fuels specified in this definition outside the bulk transfer/terminal system are subject to reporting under the regulation.</u>

*** [No changes were made to subsections (96) through (100).]

(101) <u>(A)</u> "Facility<u>,</u>" <u>unless otherwise specified in relation to natural gas distribution facilities and onshore petroleum and natural gas production facilities as defined in section 95802(a),</u> means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

<u>(B) "Facility," with respect to natural gas distribution for the purposes of sections 95150 through 95158 of MRR, means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within the State of California that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.</u>

(C) "Facility," with respect to onshore petroleum and natural gas production for the purposes of sections 95150 through 95158 of MRR, means all petroleum and natural gas equipment on a well-pad or associated with a well pad 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 and that are located in a single hydrocarbon basin as defined in section 95102(a) of MRR. Where a person or 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.

*** [No changes were made to subsection (102).]

(103) "Final Point of Delivery" means the sink specified on the NERC e-Tag, where defined points have been established through the NERC Registry. When NERC e-Tags are not used to document electricity deliveries, as may be the case within a balancing authority, the final point of delivery is the location of the load. Exported electricity is disaggregated by the final point of delivery on the NERC e-Tag.

(104)~~(103)~~"First Deliverer of Electricity" or "First Deliverer" means the owner or operator of an electricity generating facility in California or an electricity importer.

(105) "First Point of Receipt" means the generation source specified on the NERC e-Tag, where defined points have been established through the NERC Registry. When NERC e-Tags are not used to document electricity deliveries, as may be the case within a balancing authority, the first point of receipt is the location of the individual generating facility or unit, or group of generating facilities or units. Imported electricity and wheeled electricity are disaggregated by the first point of receipt on the NERC e-Tag.

*** [No changes were made to subsections (104) through (147) except to renumber.]

(150)~~(148)~~"Lead Verifier Independent Reviewer" or "Independent Reviewer" means, for purposes of this article, a lead verifier within a verification body who has not participated in conducting offset verification services for an Offset Project Developer or Authorized Project Designee for the current Offset Project Data Report and who provides an independent review of offset verification services rendered for an Offset Project Developer or Authorized Project Designee as required in section 95977.1(b)(3)(R). The independent reviewer is not required to also meet the requirements for a sector specific or offset project specific verifier.

*** [No changes were made to subsections (149) through (167) except to renumber.]

(170)~~(168)~~"Natural Gas" means a naturally occurring mixture or process derivative 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 field quality (which varies widely) or pipeline quality. For the purposes of this rule, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

(171)~~(169)~~"Natural Gas Liquids" or "NGLs", means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods. Natural gas liquids can be classified according to their vapor pressures as low (condensate), intermediate (natural gasoline), and high (liquefied petroleum gas) vapor pressure. Generally, such liquids consist of ethane, propane, butanes, ~~and~~ pentanes ~~plus,~~ and higher molecular weight hydrocarbons. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

*** [No changes were made to subsections (170) through (199) except to renumber.]

(202)~~(200)~~"Point of Delivery" or "POD" means the point on an electricity transmission or distribution system where a deliverer makes electricity available to a receiver, or available to serve load. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system, or a distribution substation where electricity is imported into California over a multi-jurisdictional retail provider's distribution system.

(203)~~(201)~~"Point of Receipt" or "POR" means the point on an electricity transmission or distribution system where an electricity receiver receives electricity from a deliverer. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

*** [No changes were made to subsection (202) except to renumber.]

(205)~~(203)~~"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.

(206)~~(204)~~ "Positive Emissions Data Verification Statement" means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered emissions data in the submitted emissions data report is free of material misstatement and that the emissions data conforms to the requirements of MRR. For purposes of this definition, 'material misstatement' shall have the same meaning as ascribed to it in section 95102(a) of MRR.

__(207)__~~(205)~~ "Positive Product Data Verification Statement" means a verification statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the __covered__ product data in the submitted emissions data report is free of material misstatement and that the product data conforms to the requirements of MRR. For purposes of this definition, 'material misstatement' shall have the same meaning as ascribed to it in section 95102(a) of MRR.

*** [No changes were made to subsections (206) through (207) except to renumber.]

__(210)__~~(208)~~ "Primary refinery products" means aviation gasoline, motor gasoline __(finished),__ kerosene-type jet fuel, distillate fuel oil, renewable liquid fuels, and asphalt. For the purpose of calculating this value for each refinery ARB will convert blendstocks into their finished fuel volumes by multiplying blendstocks by an assumed blending ratio.

*** [No changes were made to subsections (209) through (214) except to renumber.]

__(217)__~~(215)~~ "Product Data Verification Statement" means the final statement rendered by a verification body attesting whether a reporting entity's product data in their __covered__ emissions data report is free of material misstatement, and whether the product data conforms to the requirements of the MRR. For purposes of this definition, 'material misstatement' shall have the same meaning as ascribed to it in section 95102(a) of MRR.

*** [No changes were made to subsections (216) through (226) except to remember.]

__(229)__~~(227)~~"Qualified Positive Emissions Data Verification Statement" means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the __covered__ emissions data in the submitted emissions data report is free of material misstatement and is in conformance with section 95131(b)(9) of MRR, but the emissions data may include one or more other nonconformances with the requirements of MRR which do not result in a material misstatement.

(230)~~(228)~~ "Qualified Positive Product Data Verification Statement" means a statement rendered by a verification body attesting that the verification body can say with reasonable assurance that the covered product data in the submitted emissions data report is free of material misstatement and is in conformance with section 95131(b)(9) of MRR, but the product data may include one or more other nonconformance(s) with the requirements of MRR which do not result in a material misstatement.

*** [No changes were made to subsections (229) through (260) except to renumber.]

(263) "Sink" or "sink to load" or "load sink" means the sink identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Exported electricity is disaggregated by the sink on the NERC e-Tag, also referred to as the final point of delivery on the NERC e-Tag.

(264)~~(261)~~"Soda Ash Equivalent" means the total mass of all soda ash, biocarb, borax, V-Bor, DECA, PYROBOR, Boric Acid, ~~and~~ Sodium Sulfate, Potassium Sulfate, Potassium Chloride, and Sodium Chloride produced.

*** [No changes were made to subsections (262) through (263) except to renumber.]

(267) "Source of generation" or "generation source" means the generation source identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Imported electricity and wheels are disaggregated by the source on the NERC e-Tag, also referred to as the first point of receipt.

*** [No changes were made to subsections (264) through (277) except to renumber.]

(282)~~(278)~~"Unspecified Source of Electricity" or "Unspecified Source" means a source of electricity that is not a specified source at the time of entry into the transaction to procure the electricity. ~~generation that cannot be matched to a specific electricity generating facility or electricity generating unit or matched to an asset-controlling supplier recognized by ARB. Unspecified sources contribute to the bulk system power pool and typically are dispatchable, marginal resources that do not serve baseload.~~

*** [No changes were made to subsections (279) through (288) except to renumber.]

NOTE: Authority cited: Sections 38510, 38560, 38562, 38570, 38571, 38580, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 38560.5, 38564, 38565, 38570 and 39600, Health and Safety Code.

ATTACHMENT C

PROPOSED REGULATION ORDER

PROPOSED AMENDMENTS TO THE AB 32 COST OF IMPLEMENTATION FEE REGULATION

This appendix shows only proposed amendments to the AB 32 Cost of Implementation Fee Regulation (title 17, California Code of Regulations, section 95200 et seq.). The proposed amendments are made to section 95202 (Definitions) of the regulation. NOTE: Changes to the regulation are shown in underline; deletions from the regulation are shown in ~~strikeout~~. "***" indicates that sections of regulation not printed are not changed.

Amend Division 3, Chapter 1, Subchapter 10, Article 3, section 95202, title 17, California Code of Regulations to read as follows:

Article 3: Fees

Subarticle 1: AB 32 Cost of Implementation Fee Regulation

§ 95202. Definitions.

(a) For the purposes of this subarticle, the following definitions shall apply:

*** [No changes]

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

*** [No changes]

(31) "Cogeneration" means an integrated system that produces electric energy and useful thermal energy for industrial, commercial, or heating and cooling purposes, through the sequential or simultaneous use of the original fuel energy. Cogeneration must involve generation of electricity and useful thermal energy and some form of waste heat recovery. Some examples of cogeneration include: (~~A~~a) a gas turbine or reciprocating engine generating electricity by combusting fuel, which then uses a heat recovery unit to capture useful heat from the exhaust stream of the turbine or engine; (~~B~~b) steam turbines generating electricity as a byproduct of steam generation through a fired boiler;

(~~C~~c) Cogeneration systems in which the fuel input is first applied to a thermal process such as a furnace and at least some of the heat rejected from the process is then used for power production. For the purposes of this subarticle, a combined-cycle power generation unit, where~~ all of the generated steam is used for electricity generation,~~ none of the generated thermal energy is used for industrial, commercial, or heating and cooling purposes (these purposes exclude any thermal energy utilization that is either in support of or a part of the electricity generation system), is not considered a cogeneration unit.

*** [No changes]

(39) "Continuous physical transmission path" means the full transmission path shown in the physical path table of a single NERC e-tag from the first point of receipt closest to the generation source to the final point of delivery closest to the final sink. This is one criterion to establish direct delivery.

*** [No changes]

(~~43~~44) "Direct delivery of electricity" or "directly delivered" means electricity that meets any of the following criteria:

(A) The facility has a first point of interconnection with a California balancing authority;
(B) The facility has a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area;
(C) The electricity 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~~ final point of delivery~~ sink located in the State of California; or
(D) There is an agreement to dynamically transfer electricity from the facility to a California balancing authority.

*** [No changes except to renumber]

(~~49~~50) "Electricity importers" ~~are marketers and retail providers that~~ deliver imported electricity. For electricity that is scheduled with a NERC e-Tag to a final point of delivery inside the State of California,~~ delivered between balancing authority areas,~~ the electricity importer is identified on the NERC ~~E~~e-~~t~~Tag as the purchasing-selling entity (PSE) on the last segment of the tag's physical path with the point of receipt located outside the State of California and the point of delivery located inside the State of California. For facilities physically located outside the State of California with first point of interconnection to a California balancing authority's transmission and distribution system, when the electricity is not scheduled on a NERC e-Tag, the importer is the facility operator or scheduling coordinator. Federal and State agencies are subject to the regulatory authority of ARB under this article and include Western Area Power Administration (WAPA), Bonneville Power Administration (BPA), and California Department of Water Resources (DWR).

*** [No changes except to renumber]

(63) "Final point of delivery" means the sink specified on the NERC e-Tag, where defined points have been established through the NERC Registry. When NERC e-Tags are not used to document electricity deliveries, as may be the case within a balancing authority, the final point of delivery is the location of the load. Exported electricity is disaggregated by the final point of delivery on the NERC e-Tag.

(~~62~~64) "First deliverer of electricity" or "first deliverer" means ~~either~~ the owner or operator of an electricity generating facility in California, or an electricity importer.

(65) "First point of delivery in California" means the first defined point on the transmission system located inside California at which imported electricity and electricity wheeled through California may be measured, consistent with defined points that have been established through the NERC Registry.

(66) "First point of receipt" means the generation source specified on the NERC e-Tag, where defined points have been established through the NERC Registry. When NERC e-Tags are not used to document electricity deliveries, as may be the case within a balancing authority, the first point of receipt is the location of the individual generating facility or unit, or group of generating facilities or units. Imported electricity and wheeled electricity are disaggregated by the first point of receipt on the NERC e-Tag.

*** [No changes except to renumber]

(~~83~~88) "Liquefied petroleum gas" or "LP-Gas" or "LPG" means a flammable mixture of hydrocarbon gases used as a fuel. LPG is a natural gas liquid (NGL) that is ~~can be mixtures of~~ primarily a mixture of propane~~,~~ ~~primarily~~ and butane, ~~or mixtures of propane or butane~~with small amounts of propene (propylene) and ethane. The most common specification categories are propane grades HD-5, HD-10, and commercial grade propane, and propane/butane mix. ~~LPG includes~~

~~propane grades HD-5, HD-10, and commercial grade propane.~~ LPG also includes both odorized and non-odorized liquid petroleum gas, and is also referred to as ~~LGP, GLP, LP-Gas and~~ propane.

*** [No changes except to renumber]

(~~95~~ 100)"Natural gas" means a naturally occurring mixture or process derivative 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 field quality (which varies widely) or pipeline quality. For the purposes of this subarticle, the definition of natural gas includes similarly constituted fuels such as field production gas, process gas, and fuel gas.

*** [No changes except to renumber]

(~~106~~111) "Point of delivery" or "POD" means the point on an electricity transmission or distribution system where a deliverer makes electricity available to a receiver, or available to serve load. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system, or a distribution substation where electricity is imported into California over a multi-jurisdictional retail provider's distribution system.

(112) "Point of receipt" or "POR" means the point on an electricity transmission or distribution system where an electricity receiver receives electricity from a deliverer. This point can be an interconnection with another system or a substation where the transmission provider's transmission and distribution systems are connected to another system.

*** [No changes except to renumber]

(131) "Sink" or "sink to load" or "load sink" means the sink identified on the physical path of NERC e-Tags, where defined points have been established through the NERC Registry. Exported electricity is disaggregated by the sink on the NERC e-Tag, also referred to as the final point of delivery on the NERC e-Tag.

*** [No changes except to renumber]

(~~134~~141)"Unspecified source of electricity" or "unspecified source" means a source of electricity ~~procured and delivered without limitation at the time of a transaction to a specific facility's or unit's generation~~that is not a specified source at the time of entry into the transaction to procure the electricity. ~~Unspecified sources contribute to the bulk system power pool and typically are dispatchable, marginal resources that do not serve baseload.~~

*** [No changes except to renumber]

NOTE: Authority cited: Section 38510, 38597, 39600 and 39601, Health and Safety Code.
Reference: Sections 38530, 39600 and 39601, Health and Safety Code.