ATTACHMENT 1

PROPOSED 15-DAY MODIFICATIONS

Subchapter 10. Climate Change

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

*[NOTE: This document shows proposed modifications to the originally proposed amendments to the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (Division 3, Chapter 1, Subchapter 10, Article 2, sections 95100 to 95157, title 17, California Code of Regulations) set forth in Attachment A to the Staff Report: Initial Statement of Reasons, released on August 1, 2012. The original proposed amendments are shown in underline; deletions from the regulation are shown in ~~strikeout~~. The additional proposed modifications made available with this "15-day" notice dated October 9, 2012 are shown in double-underline to indicate additions and ~~double strikeout~~ to indicate deletions. "***" indicates that sections of regulation not printed are not changed.]*

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.

***

(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~~ three 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.

***

§ 95102. Definitions.

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

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

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

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

(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.

*** [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 from the facility or generating unit, ~~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]

(~~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]

(~~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, electricity transactions, and tariff provisions, without regard to duration, or written agreements to import or export on behalf of another entity, as long as that other entity also reports to ARB the same imported or exported electricity. A power contract for a specified source is a contract that is contingent upon delivery of power from a particular facility, unit, or asset-controlling supplier's system that is designated at the time the transaction is executed.

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

(392) "Refiner" means, for purposes of this article, an individual entity or a corporate-wide entity that delivers transportation fuels to end users in California that were produced by petroleum refineries owned by that entity or a subsidiary of that entity.

*** [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.

***

(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 requirements of this paragraph also apply to electric power entities that are electricity importers or exporters that have not met the requirements for cessation in section 95101(h)(4). 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).

***

(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). Flow meters and other measurement devices that were calibrated prior to January 1, 2012 using procedures specified in previous versions of the Mandatory Reporting Regulation or methods specified in 40 CFR Part 98 must be 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).

***

(6) In addition to the specific calibration requirements specified below, and, if applicable, the 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~~%~~.

***

(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, including strap-on meters or engineering methods. 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.

***

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

***

§ 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.*

***

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

***

(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:

***

(M) Provide the primary facility name, total number ~~serial numbers~~ of Renewable Energy Credits (RECs), the vintage year and month, and serial numbers of the RECs as specified below:

***

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

***

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

***

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, position holders of fossil fuels and biomass-derived fuels that supply fuel at ~~a~~ California terminal racks, ~~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.~~

***

(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:

***

(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 Table 2 of this section, ~~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.

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~~:

***

(3) *Onshore natural gas processing.* Natural gas processing means the separation of natural gas liquids (NGLs) or non-methane 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. This industry segment also includes all booster stations owned and/or operated by the facility owner/operator.

(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. This industry segment also includes all booster stations owned and/or operated by the facility owner/operator.

***

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.

***

§ 95153. Calculating GHG emissions.

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 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 continuous 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 continuous high bleed devices and pneumatic pumps. The operator may choose to also meter flow to any or all low bleed and intermittent 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~~b). 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.

***

(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 intermittent bleed and continuous 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.

***

(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.

***

(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)(5~~6~~) of this section.

(3) *Calculation Methodology 3.* If CEMS or a vent meter is not installed, the operator may use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equations 4A or 4B of this section. If inlet gas

flow rate is known, use Equation 4A. If outlet gas flow rate is known, use Equation 4B.

$$E_{\alpha,CO2} = V_{in} * [(Vol_I - Vol_O)/(1-Vol_O)] \qquad \text{(Eq. 4a)}$$

$$E_{\alpha,CO2} = V_{out} * [(Vol_I – Vol_O)/(1-Vol_I)] \qquad \text{(Eq. 4B)}$$

Where:
$E_{\alpha, CO2}$= 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.
V_{out}= Total annual volume of natural gas flow out of the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (c)(4) of this section.
Vol_I= Volume fraction of CO_2 content in natural gas into the AGR unit as determined in paragraph (c)(6) of this section.
Vol_o= Volume fraction of CO_2 content in natural gas out of 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). If the operator does not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.
(5) If 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 section 95154(b).
(6) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If 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_I according to methods set forth in section 95154(b).
(7) Determine volume fraction of CO_2 content in natural gas out of the AGR unit using one of the methods specified in paragraph (c)(7) of this section.

1. 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.
2. 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 section 95154(b).
3. Use sales line quality specification for CO_2 in natural gas.

(8) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (r) 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 emission estimated in paragraphs (c)(1) through (c)(10) of this section downward by the magnitude of emission recovered and transferred outside the facility.

~~(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.~~

$$\cancel{E_{CO2} = V_{in} * \left[Y_{CO2-in} * \left(1 - Y_{H2S-spec}\right) - Y_{CO2-out} * \left(1 - Y_{H2S-in}\right)\right] / \left(1 - Y_{H2S-spec} - Y_{CO2-out}\right)} \quad \text{(Eq. 4)}$$

~~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.~~

~~$Y_{CO2\text{-}in}$ = Mole fraction of CO_2 in natural gas into the AGR unit as determined in paragraph (c)(5) of this section.~~

~~$Y_{CO2\text{-}out}$ = Mole fraction of CO_2 in natural gas out of the AGR unit as determined in paragraph (c)(6) of this section.~~

~~$Y_{H2S\text{-}spec}$ = 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.~~

~~$Y_{H2S\text{-}in}$ = 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 $Y_{CO2\text{-}in}$ 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.~~

***

(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. Engineering estimates based on best available data may also be used to determine the temperature and pressure variables used in the Equations 13 and 14 if monitoring data is unavailable.

***

(h) *Dump Valves.* ~~*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).

***

(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. If GOR from each well is not available, the GOR from a cluster of wells in the same basin shall be used.

***

(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.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \qquad \text{(Eq. 27)}$$

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 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; 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_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.

***

(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.

***

(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).~~ If the facility does not have a continuous gas composition analyzer, then it must use an annual average gas composition based on the most recent available analysis of the facility.

***

(v) *Crude Oil, ~~and~~ Condensate, and Produced Water Dissolved CO_2 and CH_4*. The operator must calculate dissolved CO_2 and CH_4 in crude oil, ~~and~~ condensate, and produced water. Emissions must be reported for crude oil, ~~and~~ condensate, and produced water sent to ~~a~~ storage tanks, ~~or~~ ponds, and holding facilities.

(1) Calculate CO_2 and CH_4 emissions from crude oil, ~~and~~ condensate, and produced water using Equation 33A:

$$\cancel{E_{CO2/CH4} = (S_{cdc} * V_{cdc})(1-(VR*CE))}$$

$$E_{CO2/CH4} = (S * V)(1-(VR*CE)) \qquad \text{(Eq. 33A)}$$

Where:

$E_{CO2/CH4}$ = Annual CO_2 or CH_4 emissions in metric tons.

~~S_{cc}~~ S = Mass of CO_2 or CH_4 liberated in a flash liberation test per barrel of crude oil, condensate, and produced water (as determined in paragraph (v)(1)(A)1, ~~=~~ or mass of CO_2 or CH_4 recovered in a ~~VRU~~ vapor recovery system per barrel of crude oil, ~~and~~ condensate, or produced water (as determined in ~~paragragh~~ paragraph (v)(1)(A)2.

~~V_{cc}~~ V = Barrels of crude oil, ~~or~~ condensate, or produced water sent to tanks, ponds, or holding ~~facility~~ facilities annually.

VR = Percentage of time the vapor recovery ~~unit~~ system was operational (expressed as a decimal).

CE = Collection efficiency of the vapor recovery system (expressed as a decimal).

(A) ~~S_{pw}~~ S (the mass of CO_2 or CH_4 per barrel of crude oil, ~~and~~ condensate, or 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 crude oil, ~~and~~ condensate, or produced water when the

crude oil, ~~or~~ condensate, or produced 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, American Society for Testing and Materials, or U.S. EPA 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, or 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 crude oil, ~~and~~ condensate, or produced water as follows:

a. Measure the annual gas stream volume captured by the vapor recovery system.

b. Calculate the annual mass of CO_2 and CH_4 in the gas stream using the gas stream volume and mole percentage of CO_2 and CH_4 as determined by a laboratory analysis of an annual gas stream sample.

c. Calculate S by dividing the total mass of CO_2 and CH_4 in the gas stream by the total volume, in barrels, of the crude oil, condensate, or produced water throughput of the storage tank system.

d. ~~by sampling (under representative operating conditions and analysis of the vapor recovery unit (VRU) gas stream to determine the mass of CO2 and CH4 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 CO2 and CH4 in the gas stream and to calculate the annual emission rate.~~ Vapor recovery system measurements and analyses may include gases from crude oil, ~~and~~ condensate, and produced water.

(B) Emissions resulting from the destruction of the ~~VRU~~ vapor recovery system gas stream shall be reported using the Flare Stack reporting provisions in paragraph (l) of this section.

~~(w) *Produced Water Dissolved CO2 and CH4.* The operator must calculate dissolved CO2 and CH4 in produced water. Emissions must be reported for produced water sent to a storage tank or ponds and holding facilities.~~

~~(1) Calculate CO2 and CH4 emissions from produced water using Equation 34:~~

$$\cancel{E_{CO2/CH4} = (S_{pw} * V_{pw})(1 - VR * CE)} \qquad \text{~~(Eq. 34)~~}$$

~~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~~=~~.

(w) ***Reserved***
(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).

***

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.

***

(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~~ estimation.
(D) Other company records.

***

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. Additional Data Reporting Requirements.

Operators must conform with the data reporting requirements in ~~40 CFR §98.236~~ section 95157 except as specified below.

(a) In addition to the data required by section 95157,~~40 CFR §98.236 (a)-(c),~~ the operator of an onshore and offshore petroleum and natural gas production facility must report the following data disaggregated within the basin by each facility that lies within contiguous property boundaries:

***

(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~~ energy generated (MMBtu) and the CO_2e emissions associated with this output;

(B) Thermal ~~output~~ energy (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;

***

(e) The operator of a natural gas liquid fractionating facility or a natural gas processing 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.

***

(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.

***

(3) For each acid gas removal unit (refer to Equation 3 and Equations 4a-b of section 95153), report the following:.

***

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.