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

Amend Division 3, Chapter 1, Subchapter 10, Article 2, sections 95100, 95101, 95102, 95103, 95104, 95105, 95106, 95107, 95108, 95109, 95110, 95111, 95112, 95113, 95114, 95115, 95130, 95131, 95132, and 95133, title 17, California Code of Regulations; repeal section 95125, title 17, California Code of Regulations; and add new sections 95100.5, 95116, 95117, 95118, 95119, 95120, 95121, 95122, 95123, 95129, 95150, 95151, 95152, 95153, 95154, 95155, 95156, 95157, and 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

§ 95100. Table of Contents

§ 95100.5. Purpose and Scope

(a) The purpose of this article is to establish mandatory greenhouse gas (GHG) reporting, verification, and other requirements for operators of certain facilities that directly emit GHGs, suppliers of certain fuels and carbon dioxide, electric power entities, verifiers of GHG emissions data reports and offset project data reports submitted pursuant to the Cap-and-Trade Regulation, and verification bodies. This article is designed to meet the requirements of section 38530 of the Health and Safety Code, and to support GHG regulatory programs of the California Air Resources Board.

(b) *Organization of this Article.* Subarticle 1 specifies general requirements for the reporting of GHG emissions that apply to all reporting entities listed in section 95101. Subarticle 2 specifies reporting requirements and calculation methods for specific types of facilities and entities. Subarticle 3 specifies additional requirements for reported data, including procedures for the substitution for missing data. Subarticle 4 specifies verification requirements for GHG emissions data reports, requirements for those who provide verification services for GHG reporting entities, and accreditation requirements for verifiers of emissions data reports and offset project data reports. Subarticle 5 specifies reporting requirements and calculation methods for petroleum and natural gas production, processing, and storage facilities.

(c) *U.S. EPA GHG Reporting Rule.* This article incorporates various provisions of title 40, Code of Federal Regulations (CFR), Part 98. These provisions are a portion of the U.S. Environmental Protection Agency (U.S. EPA) Final Rule on Mandatory Reporting of Greenhouse Gases. Unless otherwise specified, references in this article to 40 CFR Part 98 are to those requirements promulgated by U.S. EPA on October 30, 2009, July 12, 2010, September 22, 2010, and October 7, 2010.

(d) Except as otherwise specifically provided:

(1) Wherever the term “Administrator” is used in the federal rules referred to in this article, the term “Executive Officer of the California Air Resources Board” or “Executive Officer” shall be substituted.
(2) Wherever the term “EPA” is used in the federal rules referred to in this article, the term “California Air Resources Board” or “ARB” shall be substituted.
(3) In cases where the owner and operator of a facility or a supplier are not the same party, the operator is responsible for compliance with this article.

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

§ 95101. Applicability.

(a) *General Applicability.*

(1) This article applies to the following entities:

(A) Operators of facilities located in California and included in 40 CFR §98.2(a)(1)-(3);

(B) Suppliers of fuels or carbon dioxide provided for consumption within California that are included in 40 CFR §98.2(a)(4) or specified below in subsection (c);

(C) Electric power entities as specified below in subsection (d); and,

(D) Operators of petroleum or natural gas systems as specified below in subsection (e).

(2) Any reporting entity that fits into one or more of the categories in subsection (a)(1) above for calendar year 2011 or later must submit an emissions data report for that year and for subsequent calendar years, except as provided in the report cessation provisions of subsection (h) of this section. The emissions data report must cover all source categories and GHGs for which calculation methods are provided or referenced in this article for the reporting entity. Except as otherwise specified in this article, the report must be compiled using the methods specified by source category in 40 CFR Part 98.

(3) *Verifiers and Verification Bodies*. In addition to the reporting entities specified in subsection (a)(1) above, this article contains requirements for entities acting as verification bodies and individuals acting as third party verifiers of emissions data reports and offset project data reports. These requirements are specified in sections 95130 through 95133 of this article.

(b) *Calculating GHG Emissions Relative to Reporting Thresholds.* For industrial sectors for which an emissions-based applicability threshold is specified in 40 CFR §98.2, the reporting entity must apply a threshold of 10,000 metric tons of CO_2e for reporting under this article. Operators of facilities and suppliers must calculate their emissions using the requirements of 40 CFR §98.2(b)-(g), using a 10,000 metric tons of CO_2e threshold to determine if reporting is required. For purposes of determining reporting applicability for a 10,000 metric tons of CO_2e threshold, combustion and process emissions of CO_2, CH_4 and N_2O must be included, but fluorinated gases may be excluded.

(1) Facilities with stationary combustion emissions are included according to the requirements of 40 CFR 98.2(a)(3), except that the thresholds for reporting in California are 10,000 metric tons of CO_2e and an aggregate maximum heat input capacity of 12 mmBtu/hr or greater.

(2) Notwithstanding 40 CFR §98.2(b)(2), operators of facilities and suppliers must include emissions of CO_2 from the combustion of biomass and other biofuels when determining applicability relative to thresholds for emissions reporting and cessation of reporting.
(3) Operators of geothermal generating units must report when total facility emissions of CO_2 and CH_4 equal or exceed 10,000 metric tons of CO_2e.

(c) *Fuel and CO_2 Suppliers.* The suppliers listed below, as defined in section 95102(a), are required to report under this article when they import and/or deliver an annual quantity of products that, when completely combusted or oxidized, 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:

(1) Position holders at terminals and refineries delivering petroleum products and/or biomass-derived fuels, as described in section 95121;
(2) Enterers that import petroleum products and/or biomass-derived fuels outside the bulk transfer/terminal system, as described in section 95121;
(3) Producers of biomass-derived fuels, as described in section 95121;
(4) All refiners that produce liquefied petroleum gas, without regard to product quantities, as described in section 95121;
(5) Operators of interstate pipelines delivering natural gas, as described in section 95122;
(6) California consignees of liquefied petroleum gas, as described in section 95122;
(7) Local distribution companies who are public utility gas corporations or publicly-owned natural gas utilities delivering natural gas, as described in section 95122;
(8) Operators of intrastate pipelines delivering natural gas as described in section 95122;
(9) All natural gas liquid fractionators, without regard to product quantities produced, as described in section 95122;
(10) All producers of carbon dioxide without regard to product quantity produced, and importers of carbon dioxide with annual bulk imports into California of 10,000 metric tons or more, as described in section 95123.

(d) *Electric Power Entities.* The entities listed below are required to report under this article:

(1) Electricity importers and exporters, as defined in section 95102(a);
(2) Retail providers, including multi-jurisdictional retail providers, as defined in section 95102(a);
(3) California Department of Water Resources (DWR);
(4) Western Area Power Administration (WAPA);
(5) Bonneville Power Administration (BPA).

(e) *Petroleum and Natural Gas Systems.* The facilities listed below, as 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:

(1) Offshore petroleum and natural gas production facilities;
(2) Onshore petroleum and natural gas production facilities, when the reporting entity meets the requirements of section 95151(a)(1);
(3) Onshore natural gas processing plants;
(4) Onshore natural gas transmission compression facilities;
(5) Underground natural gas storage facilities;
(6) Liquefied natural gas storage facilities;
(7) Liquefied natural gas import and export facilities;
(8) Natural gas distribution facilities.

(f) *Exclusions*. This article does not apply to, and greenhouse gas emissions reporting is not required for:

(1) Electricity generating facilities that are solely powered by nuclear, hydroelectric, wind, or solar energy, unless on-site stationary combustion and process emissions equal or exceed 10,000 metric tons of CO_2e;
(2) Generating units designated as backup or emergency generators in a permit issued by an air pollution control district or air quality management district;
(3) Fire suppression systems and equipment;
(4) Portable equipment, except where specifically required to report under 40 CFR Part 98 or this article;
(5) Primary and secondary schools with a NAICS code of 611110.

(g) *Demonstration of Nonapplicability*. The Executive Officer may request a demonstration from any operator, supplier, or entity that the operator, supplier, or entity does not meet one or more of the applicability criteria specified in this article. Such demonstration must be provided to the Executive Officer within 20 days of receipt of a written request.

(h) *Cessation of Reporting*. Except as otherwise specified below, 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 operator or supplier must provide the letter notifications specified 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.
(2) Wherever 40 CFR §98.2(i)(2) states “15,000 metric tons of CO_2e per year,” the phrase “5,000 metric tons of CO_2e per year” shall be substituted.
(3) 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.

(4) The verification requirements of this article do not apply to the first full year of non-operation following a permanent shutdown, but continue to apply to prior emissions data reports.

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

Subarticle 1: General Requirements for Greenhouse Gas Reporting

§ 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.

(2) "Acid gas" means hydrogen sulfide (H_2S) and carbon dioxide (CO_2) contaminants that are separated from sour natural gas by an acid gas removal.

(3) "Acid gas removal unit (AGR)" means a process unit that separates hydrogen sulfide and/or carbon dioxide from sour natural gas using liquid or solid absorbents or membrane separators.

(4) "Acid gas removal vent stack emissions" mean the acid gas separated from the acid gas absorbing medium (e.g., an amine solution) and released with methane and other light hydrocarbons to the atmosphere or a flare.

(5) "Additional" means, in the context of offset credits, greenhouse gas emission reduction or GHG removal enhancement activities, that result in greenhouse gas reduction or GHG removal enhancements, other than those activities required by law or regulation, any legally binding mandate, or any greenhouse gas reduction or GHG removal enhancement activities that would otherwise occur in a conservative business-as-usual scenario.

(6) "Adverse verification statement" means a verification statement rendered by a verification body attesting that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement.

(7) "Air injected flare" means a flare in which air is blown into the base of a flare stack to induce complete combustion of low Btu natural gas (i.e., high non-combustible component content.)

(8) "Allowance" means, unless the plain meaning of the word indicates otherwise, a limited tradable authorization to emit up to one metric ton of carbon dioxide equivalent.

(9) "Annual" means with a frequency of once a year; unless otherwise noted, annual events such as reporting requirements will be based on the calendar year.

(10) "API" means the American Petroleum Institute.

(11) "AQMD/APCD" or "air district" means air quality management district or air pollution control district.

(12) "ARB" means the California Air Resources Board.

(13) "Artificial island" is a plot of land or other structure constructed on a body of water to support onshore petroleum or natural gas production.

(14) "Asphalt" means a dark brown-to-black cement-like material obtained by petroleum processing and containing bitumens as the predominant component. It includes crude asphalt as well as the following finished products: cements, fluxes, the asphalt content of emulsions (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts.

(15) "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. Asset controlling suppliers include Bonneville Power Administration (BPA) and the two multi-jurisdictional retail providers in California: PacifiCorp and Sierra Pacific Power Company.

(16) "Assigned emissions level" means an amount of emissions, in CO_2e, assigned to the reporting entity by the Executive Officer in the case of a non submitted/non-verified emissions data report or following the issuance of an adverse verification statement.

(17) "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.

(18) "ASTM" means the American Society of Testing and Materials.

(19) "Authorized project designee" means an entity authorized by an Offset Project Operator to act on behalf of the Offset Project Operator.

(20) "Balancing authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.

(21) "Balancing authority area" means the collection of generation, transmission, and loads within the metered boundaries of a balancing authority. A balancing authority maintains load-resource balance within this area.

(22) "Barrel" means a volume equal to 42 U.S. gallons.

(23) “Bias” means systematic error, resulting in measurements that will be either consistently low or high relative to the reference value.

(24) “Biodiesel” means a diesel fuel substitute produced from nonpetroleum renewable resources that meet the registration requirements for fuels and fuel additives established by the U.S. Environmental Protection Agency under section 211 of the Clean Air Act. It includes biodiesel that is all of the following:

(A) Registered as a motor vehicle fuel or fuel additive under 40 CFR Part 79;

(B) A mono-alkyl ester;

(C) Meets American Society for Testing and Material designation ASTM D 6751-08 (*Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels, 2008*);

(D) Intended for use in engines that are designated to run on conventional diesel fuel; and

(E) Derived from nonpetroleum renewable resources.

(25) “Biogenic portions of CO_2 emissions” means carbon dioxide emissions generated as the result of biomass combustion from combustion units.

(26) “Biomass” means non-fossilized and biodegradable organic material originating from plants, animals and micro-organisms, including products, byproducts, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material. For the purpose of this article, biomass includes both California Renewable Portfolio Standard (RPS) eligible and non-eligible biomass as defined by the California Energy Commission.

(27) “Biomass-derived fuels” or “biomass fuels” or “biofuels” or “biomass-based fuels” means fuels derived from biomass.

(28) “Blendstocks” are petroleum products used for blending or compounding into finished motor gasoline. These include RBOB (reformulated blendstock for oxygenate blending) and CBOB (conventional blendstock for oxygenate blending), but exclude oxygenates, butane, and pentanes plus.

(29) “Blowdown” means the act of emptying or depressurizing a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower.

(30) “Blowdown vent stack emissions” mean natural gas released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

(31) “Bone dry short ton” means an amount of material that weighs 2,000 pounds at zero percent moisture content.

(32) “Bottom ash” means ash that collects at the bottom of a combustion chamber.

(33) “Bottoming cycle” means a type of cogeneration system in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.

(34) “British thermal unit” or “Btu” means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.

(35) “Bulk transfer/terminal system” means a fuel distribution system consisting of refineries, pipelines, vessels, and terminals.

(36) “Busbar” means a power conduit of a facility with electricity generating units that serves as the starting point for the electricity transmission system.

(37) “Business-as-usual scenario” means the set of conditions reasonably expected to occur within the offsets project boundary in the absence of the financial incentives provided by offset credits, taking into account all current laws and regulations, as well as current economic and technological trends.

(38) “Butane” or “n-Butane” is a paraffinic straight-chain hydrocarbon with molecular formula C_4H_{10}.

(39) “Bypass dust” means discarded dust from the bypass system dedusting unit of suspension preheater, precalciner and grate preheater kilns, consisting of fully calcined kiln feed material.

(40) “Calcination” means the thermal decomposition of carbonate minerals, such as calcium carbonate (the principal mineral in limestone) to form calcium oxide in a cement kiln.

(41) “Calcine” means to heat a substance so that it oxidizes or reduces.

(42) “Calendar year” means the time period from January 1 through December 31.

(43) "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.

(44) "Cap-and-Trade Regulation" or "Cap-and-Trade Program" means ARB's regulation establishing the California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms set forth in title 17, California Code of Regulations, Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

(45) "California consignee" means the person or entity in California to whom the shipment is to be delivered.

(46) "California Energy Commission" or "CEC" means the California Energy Resources Conservation and Development Commission.

(47) "Carbon dioxide" or "CO_2" means the most common of the six primary greenhouse gases, consisting on a molecular level of a single carbon atom and two oxygen atoms.

(48) "Carbon dioxide equivalent" or "CO_2 equivalent" or "CO_2e" means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas.

(49) "Catalyst" means a substance added to a chemical reaction, which facilitates or causes the reaction, and is not consumed by the reaction.

(50) "Cement" means a building material that is produced by heating mixtures of limestone and other minerals or additives at high temperatures in a rotary kiln to form clinker, followed by cooling and grinding with blended additives. Finished cement is a powder used with water, sand and gravel to make concrete and mortar.

(51) "Cement kiln dust" or "CKD" means the fine-grained, solid, highly alkaline waste removed from cement kiln exhaust gas by air pollution control devices. CKD consists of partly calcined kiln feed material and includes all dust from cement kilns and bypass systems including bottom ash and bypass dust.

(52) "Cement plant" means an industrial structure, installation, plant, or building primarily engaged in manufacturing Portland, natural, masonry, pozzolanic, and other hydraulic cements, and typically identified by NAICS code 327310.

(53) "Centrifugal compressor" means any equipment that increases the pressure of a process natural gas by centrifugal action, employing rotating movement of the driven shaft.

(54) “Centrifugal compressor dry seals” means a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas from escaping to the atmosphere.

(55) “Centrifugal compressor dry seals emissions” means natural gas released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

(56) “Centrifugal compressor wet seal degassing venting emissions” means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

(57) “Certification” or “certify” refers to the procedure in 40 CFR §98.4(e), as required for reports submitted to ARB under this article.

(58) “City gate” means a location at which natural gas ownership or control passes from one party to another, neither of which is the ultimate consumer. In this article, in keeping with common practice, the term refers to a point or measuring station at which a local gas distribution utility receives gas from a natural gas pipeline company or transmission system. Meters at the city gate station measure the flow of natural gas into the local distribution company system and typically are used to measure local distribution company system sendout to customers.

(59) “Clinker” means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.

(60) “Coal” means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–05 “Standard Classification of Coals by Rank” (September 2005).

(61) “Coal bed methane” or “CBM” means natural gas which is extracted from underground coal deposits or “beds.”

(62) “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.

(63) “Cogeneration unit” means a unit 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.

(64) “Coke (petroleum)” means a solid residue consisting mainly of carbon which results from the cracking of petroleum hydrocarbons in processes such as coking and fluid coking. This includes catalyst coke deposited on a catalyst during the refining process which must be burned off in order to regenerate the catalyst.

(65) “Combustion emissions” means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

(66) “Combustion source” means a source of emissions resulting from combustion.

(67) “Commercial propane” means liquefied petroleum gas that has any mixture of gasses that can sustain combustion.

(68) “Compliance instrument” means an allowance, offset credit or sector-based offset credit. Each compliance instrument can be used to fulfill a compliance obligation equivalent to up to one metric ton of CO_2e.

(69) “Compliance obligation” means the quantity of verified reported emissions for which a covered entity must submit compliance instruments to ARB.

(70) “Compliance offset protocol” means an offset protocol adopted by the Board.

(71) “Compliance period” means the three-year period for which the compliance obligation is calculated for covered entities pursuant to the Cap-and-Trade Regulation.

(72) “Component” for the purposes of sections 95150 to 95158 of this article means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

(73) “Compressor” means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas.

(74) “Condensate” means hydrocarbon and other liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at storage conditions, includes both water and hydrocarbon liquids.

(75) “Conservative” means, in the context of offsets, utilizing project baseline assumptions, emission factors, and methodologies that are more likely than not to understate net GHG reductions or GHG removal enhancements for an offset project to address uncertainties affecting the calculation or measurement of GHG reductions or GHG removal enhancements.

(76) “Conflict of interest” means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable or potentially unable to render an impartial verification statement of a potential client’s greenhouse gas emissions data report, or the person or body’s objectivity in performing verification services is or might be otherwise compromised.

(77) “Consignee” means the same as “California consignee.”

(78) “Continuous emissions monitoring system” or “CEMS” means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

(79) “Conventional wells” mean gas wells in producing fields that do not employ hydraulic fracturing to produce commercially viable quantities of natural gas.

(80) “Cracking” means the process of breaking down larger molecules into smaller molecules, utilizing catalysts and/or elevated temperatures and pressures.

(81) "Crude oil" means a mixture of hydrocarbons that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. Depending on the characteristics of the crude stream, it may also include any of the following:

(A) Small amounts of hydrocarbons that exist in gaseous phase in natural underground reservoirs but are liquid at atmospheric conditions (temperature and pressure) after being recovered from oil well (casing-head) gas in lease separators and are subsequently commingled with the crude stream without being separately measured. Lease condensate recovered as a liquid from natural gas wells in lease or field separation facilities and later mixed into the crude stream is also included.

(B) Small amounts of non-hydrocarbons, such as sulfur and various metals.

(C) Drip gases, and liquid hydrocarbons produced from tar sands, oil sands, gilsonite, and oil shale.

(D) Petroleum products that are received or produced at a refinery and subsequently injected into a crude supply or reservoir by the same refinery owner or operator.

Liquids produced at natural gas processing plants are excluded. Crude oil is refined to produce a wide array of petroleum products, including heating oils; gasoline, diesel and jet fuels; lubcirants; asphalt; ethane, propane and butane; and many other products used for their energy or chemical content.

(82) "Customer" means a purchaser of electricity not for the purposes of retransmission or resale.

(83) "Data year" means the calendar year in which emissions occurred.

(84) "Delivered electricity" means electricity that was distributed from a PSE and received by a PSE or electricity that was generated, transmitted, and consumed.

(85) "De minimis" means those emissions reported for a source or sources that are calculated using alternatives methods selected by the operator, subject to the limits specified in section 95103(i).

(86) "Dehydrator" means a device in which a liquid absorbent (including desiccant, ethylene glycol, diethylene glycol, or triethylene glycol) directly contacts a natural gas stream to absorb water vapor.

(87) "Dehydrator vent stack emissions" means natural gas released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

(88) "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.

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

(90) "Desiccant" means a material used in solid-bed dehydrators to remove water from raw natural gas by adsorption. Desiccants include activated alumina, palletized calcium chloride, lithium chloride and granular silica gel material. Wet natural gas is passed through a bed of the granular or pelletized solid adsorbent in these dehydrators. As the wet gas contacts the surface of the particles of desiccant material, water is adsorbed on the surface of these desiccant particles. Passing through the entire desiccant bed, almost all of the water is adsorbed onto the desiccant material, leaving the dry gas to exit the contactor.

(91) “Designated representative” means the person responsible for certifying, signing, and submitting the GHG emissions data report.

(92) “Diesel fuel” means Distillate Fuel No. 1 and Distillate Fuel No. 2, including dyed and nontaxed fuels.

(93) “Distillate fuel oil” means a classification for one of the petroleum fractions produced in conventional distillation operations and from crackers and hydrotreating process units. The generic term distillate fuel oil includes kerosene, diesel fuels (Diesel Fuels No. 1, No. 2, and No. 4), and fuel oils (Fuel Oils No. 1, No. 2, and No. 4).

(94) “Distillate Fuel No. 1” has a maximum distillation temperature of 550°F at the 90 percent recovery point and a minimum flash point of 100°F and includes fuels commonly known as Diesel Fuel No. 1 and Fuel Oil No. 1, but excludes kerosene. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

(95) “Distillate Fuel No. 2” has a minimum and maximum distillation temperature of 540°F and 640°F at the 90 percent recovery point, respectively, and includes fuels commonly known as Diesel Fuel No. 2 and Fuel Oil No. 2. This fuel is further subdivided into categories of sulfur content: High Sulfur (greater than 500 ppm), Low Sulfur (less than or equal to 500 ppm and greater than 15 ppm), and Ultra Low Sulfur (less than or equal to 15 ppm).

(96) “Distillate Fuel No. 4” is a distillate fuel oil made by blending distillate fuel oil and residual fuel oil, with a minimum flash point of 131°F.

(97) “EIA” means the Energy Information Administration. The Energy Information Administration (EIA) is a statistical agency of the United States Department of Energy.

(98) “E&P Tank” means E&P Tank Version 2.0 for Windows software, copyright 1996-1999 by the American Petroleum Institute and the Gas Research Institute (published 2000).

(99) “Electricity consumed on-site” means the amount of electricity generated on-site and used for other operations at the facility, excluding parasitic power required for operation of the electricity generating or cogeneration system. This quantity excludes electricity generated off-site, such as electricity purchased from an electric utility.

(100) “Electricity exporter” means marketers and retail providers that hold title to exported electricity. For electricity delivered between balancing authority areas, the entity that holds title to exported electricity is identified on the

NERC E-tag as the purchasing-selling entity (PSE) on 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.

(101) "Electricity generating unit" or "EGU" means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

(102) "Electricity importers" are marketers and retail providers that hold title to imported electricity. For electricity delivered between balancing authority areas, the entity that holds title to delivered electricity is identified on the NERC E-tag as the purchasing-selling entity (PSE) on 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. 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 and Power (DWR). When PSEs are not subject to the regulatory authority of ARB, including tribal nations, the electricity importer is the immediate downstream purchaser or recipient that is subject to the regulatory authority of ARB.

(103) "Electricity transaction" means the purchase, sale, import, export or exchange of electric power.

(104) "Electricity wheeled through California" means electricity that is generated outside the state of California and delivered into California with final point of delivery outside California.

(105) "Emission factor" means a unique value for determining an amount of a greenhouse gas emitted for a given quantity of activity (e.g., metric tons of carbon dioxide emitted per barrel of fossil fuel burned.)

(106) "Emissions" means the release of greenhouse gases into the atmosphere from sources and processes in a facility, including from the combustion of transportation fuels such as natural gas, petroleum products, and natural gas liquids.

(107) "Emissions data report" or "greenhouse gas emissions data report" or "report" means the report prepared by an operator or supplier each year and submitted by electronic means to ARB that provides the information required by this article.

(108) "End user" means a final purchaser of electricity or natural gas not for the purposes of retransmission or resale. In the context of natural gas consumption, an "end user" is the point to which natural gas is delivered for consumption.

(109) "Enforceable" means the authority for ARB to hold a particular party liable and to take appropriate action if any of the provisions of this article are violated.

(110) "Engineering estimation," for the purposes of sections 95150 to 95158 of this article, means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

(111) "Enhanced oil recovery" or "EOR" means the use of certain methods such as steam (thermal EOR), water flooding or gas injection into existing wells to increase the recovery of crude oil from a reservoir. In the context of this rule, EOR also applies to injection of critical phase carbon dioxide into a crude oil reservoir to enhance the recovery of oil.

(112) "Enterer" means an entity that imports motor vehicle fuel, diesel fuel, fuel ethanol, biodiesel or another biomass-derived fuel or renewable fuel and who is the importer of record under federal customs law or the owner of fuel upon import if the fuel is not subject to federal customs law.

(113) "Entity" means a person, firm, association, organization, partnership, business trust, corporation, limited liability company, company, or government agency.

(114) "Equipment" means any stationary article, machine, or other contrivance, or combination thereof, which may cause the issuance or control the issuance of air contaminants; equipment shall not mean portable equipment, tactical support equipment, or electricity generators designated as backup generators in a permit issued by an air pollution control district or air quality management district.

(115) "Ethane" is a paraffinic hydrocarbon with molecular formula C_2H_6.

(116) "Exchange agreement" means a commitment between electricity market participants to swap energy for energy. Exchange transactions do not involve transfers of payment or receipts of money for the full market value of the energy being exchanged, but may include payment for net differences due to market price differences between the two parts of the transaction or to settle minor imbalances.

(117) "Exclusive marketer" means a marketer that has exclusive rights to market electricity for a generating facility or group of generating facilities.

(118) "Executive Officer" means the Executive Officer of the California Air Resources Board, or his or her delegate.

(119) "Exported electricity" means electricity generated inside the state of California and delivered to serve load outside California. This includes electricity delivered from a point of receipt inside California, to the first point of delivery outside California, having a final point of delivery outside California. Exported electricity does not include electricity generated inside the state of California then transmitted outside of California, but with a final point of delivery inside California. Exported electricity does not include electricity generated inside the state of California that is allocated to serve the California retail customers of a multi-jurisdictional retail provider, consistent with a cost allocation methodology approved by the California Public Utilities Commission and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service.

(120) "Facility" 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.

(121) "Feedstock" means the raw material supplied to a process.

(122) "Field," in the context of oil and gas system, means standardized field names and codes of all oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List.

(123) "Finished motor gasoline" means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in spark ignition engines. Motor gasoline includes conventional gasoline, reformulated gasoline, and all types of oxygenated gasoline. Gasoline also has seasonal variations in an effort to control ozone levels. This is achieved by lowering the Reid Vapor Pressure (RVP) of gasoline during the summer driving season. Depending on the region of the country the RVP is lowered to below 9.0 psi or 7.8 psi. The RVP may be further lowered by state regulations.

(124) "Firmed and shaped electricity" means electricity that is paired with a variable renewable resource to improve dispatchability and back up the resource to assure customer load is met.

(125) "Flash point" of a volatile liquid is the lowest temperature at which it can vaporize to form an ignitable mixture in air.

(126) “Flare” means a combustion device, whether at ground level or elevated, that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame.

(127) “Flare combustion” means unburned hydrocarbons including CH_4, CO_2, and N_2O emissions resulting from the incomplete combustion of gas in flares.

(128) “Flare combustion efficiency” means the fraction of natural gas, on a volume or mole basis, that is combusted at the flare burner tip.

(129) “Flow monitor” means a component of the continuous emission monitoring system that measures the volumetric flow of exhaust gas.

(130) “Fluid catalytic cracking unit” or “FCCU” means a process unit in a refinery in which petroleum derivative feedstock is charged and fractured into smaller molecules in the presence of a catalyst, or reacts with a contact material to improve feedstock quality for additional processing, and in which the catalyst or contact material is regenerated by burning off coke and other deposits. The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat.

(131) “Fluid coking” means a thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products.

(132) “Fluorinated greenhouse gas” means sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and any fluorocarbon except for controlled substances as defined at 40 CFR Part 82, subpart A and substances with vapor pressures of less than 1 mm of Hg absolute at 25°C. With these exceptions, “fluorinated GHG” includes any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

(133) “Fossil fuel” means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material, including for example, consumer products that are derived from such materials and are combusted.

(134) “Fractionates” means the process of separating natural gas liquids into their constituent liquid products.

(135) “Fractionator” means plants that produce fractionated natural gas liquids (NGLs) extracted from produced natural gas and separate the NGLs individual component products: ethane, propane, butanes and pentane-plus (C5+). Plants that only process natural gas but do not fractionate NGLs further into component products are not considered fractionators. Some fractionators do not process production gas, but instead fractionate bulk

NGLs received from natural gas processors. Some fractionators both process natural gas and fractionate bulk NGLs received from other plants.

(136) “Fuel” means solid, liquid or gaseous combustible material. Volatile organic compounds burned in destruction devices are not fuels unless they can sustain combustion without use of a pilot fuel and such destruction does not result in a commercially useful end product.

(137) “Fuel analytical data” means data collected about fuel usage (including mass, volume, and flow rate) and fuel characteristics (including heating value, carbon content, and molecular weight) to support emissions calculation.

(138) “Fuel characteristic data” means, for the purpose of this article, properties of a fuel used for calculating GHG emissions including carbon content, high heat value, and molecular weight.

(139) “Fuel ethanol” means ethanol that meets ASTM D-4806 (August 2008) specifications for blending with gasolines for use as automotive spark-ignition engine fuel.

(140) “Fuel flowmeter system” means a monitoring system which provides a continuous record of the flow rate of fuel oil or gaseous fuel. A fuel flowmeter system consists of one or more fuel flowmeter components, all necessary auxiliary components (e.g., transmitters, transducers, etc.), and a data acquisition and handling system (DAHS).

(141) “Fuel production facility” means a facility, other than a refinery, in which motor vehicle fuel, diesel fuel or biomass-based fuel is produced.

(142) “Fuel supplier” means a supplier of petroleum products, a supplier of biomass-derived transportation fuels, a supplier of natural gas, or a supplier of liquid petroleum gas as specified in this article.

(143) “Fugitive emissions” means those emissions which are unintentional and could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

(144) “Fugitive emissions detection” means the process of identifying emissions from equipment, components, and other point sources.

(145) "Fugitive source" means a source of fugitive emissions.

(146) “Full verification” means all verification services as provided in section 95131.

(147) “Gas” means the state of matter distinguished from the solid and liquid states by: relatively low density and viscosity; relatively great expansion and

contraction with changes in pressure and temperature; the ability to diffuse readily; and the spontaneous tendency to become distributed uniformly throughout any container.

(148) “Gas conditions” means the actual temperature, volume, and pressure of a gas sample.

(149) “Gas gathering/booster stations” means centralized stations where produced natural gas from individual wells is co-mingled, compressed for transport to processing plants, transmission and distribution systems, and other gathering/booster stations which co-mingle gas from multiple production gathering/booster stations. Such stations may include gas dehydration, gravity separation of liquids (both hydrocarbon and water), pipeline pig launchers and receivers, and gas powered pneumatic devices.

(150) “Gas to oil ratio” or “GOR” means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

(151) “Generation providing entity” or “GPE” means a merchant selling energy from owned, affiliated, or contractually bound generation.

(152) “Generating unit” means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

(153) “Geothermal” means heat or other associated energy derived from the natural heat of the earth.

(154) "Global warming potential" or "GWP" means the ratio of the time-integrated radiative forcing from the instantaneous release of one kilogram of a trace substance relative to that of one kilogram of a reference gas, i.e., CO_2.

(155) “Greenhouse gas” or “GHG” means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), hydrocarbons and other fluorinated greenhouse gases as defined in this section.

(156) “Greenhouse gas emission reduction” or “GHG emission reduction” or “greenhouse gas reduction” or “GHG reduction” means a calculated decrease in GHG emissions relative to a project baseline over a specified period of time.

(157) “Greenhouse gas removal enhancement” or “GHG removal” means the calculated total mass of a GHG removed, relative to a project baseline, from the atmosphere over a specified period of time.

(158) "Greenhouse gas reservoir" or "GHG reservoir" means a physical unit or component of the biosphere, geosphere or hydrosphere with the capability to store, accumulate, or release of a GHG removed from the atmosphere by a GHG sink or a GHG captured from a GHG emission source.

(159) "Greenhouse gas sink" or "GHG sink" means a physical unit or process that removes a GHG from the atmosphere.

(160) "Gross generation" or "gross power generated" means the total electrical output of the generating facility or unit, expressed in megawatt hours (MWh) per year.

(161) "HD-5" means a consumer grade of liquefied petroleum gas that contains a minimum of 90% propane, and a maximum of 5% propylene and 5% butanes and ethane.

(162) "HD-10" means liquefied petroleum gas with no more than 10% propylene.

(163) "Heat input rate" means the product (expressed in mmBtu/hr) of the gross calorific value of the fuel (expressed in mmBtu/mass of fuel) and the fuel feed rate into the combustion device (expressed in mass of fuel/hr) and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust from other sources.

(164) "High heat value" or "HHV" means the high or gross heat content of the fuel with the heat of vaporization included. The water vapor is assumed to be in a liquid state.

(165) "High-bleed pneumatic devices" are 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 which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate in excess of six standard cubic feet per hour.

(166) "Hydrocarbons" means chemical compounds containing predominantly carbon and hydrogen.

(167) "Hydrofluorocarbons" or "HFCs" means a class of GHGs consisting of hydrogen, fluorine, and carbon.

(168) "Hydrogen" means the lightest of all gases, occurring chiefly in combination with oxygen in water; exists also in acids, bases, alcohols, petroleum, and other hydrocarbons.

(169) "Hydrogen plant" means a facility that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.

(170) “Imported electricity” means electricity generated outside the state of California and delivered to serve load inside the state of California. Imported electricity includes electricity delivered from a point of receipt located outside the state of California, to the first point of delivery located inside the state of California, having a final point of delivery in California. Imported electricity includes electricity imported into California over a multi-jurisdictional retail provider’s transmission and distribution system, or electricity imported into California over a balancing authority’s transmission and distribution system. Imported electricity includes electricity that is a result of cogeneration located outside the state of California. Imported electricity does not include electricity wheeled through California, which is electricity that is delivered into California with final point of delivery outside California.

(171) “Importer of record” means the owner or purchaser of the goods.

(172) “Inventory position” means a contractual agreement with the terminal operator for the use of the storage facilities and terminaling services for the fuel.

(173) “Intrastate pipeline” means any pipeline wholly within the state of California that is not regulated as a public utility gas corporation by the California Public Utility Commission (CPUC), not a publicly-owned natural gas utility and is not regulated as an interstate pipeline by the Federal Energy Regulatory Commission.

(174) “Interstate pipeline” means any entity that owns or operates a natural gas pipeline delivering natural gas to consumers in the state and is subject to rate regulation by the Federal Energy Regulatory Commission.

(175) "ISO" means the International Organization for Standardization.

(176) “Jurisdiction” means U.S. state or Canadian province. For purposes of this article, “U.S. state” means U.S. State, the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, and American Samoa and includes the Commonwealth of the Northern Mariana Islands. For purposes of this article, “province” means any Canadian province or territory.

(177) “Kerosene” is a light petroleum distillate with a maximum distillation temperature of 400°F at the 10-percent recovery point, a final maximum boiling point of 572°F, a minimum flash point of 100°F, and a maximum freezing point of -22°F. Included are No. 1-K and No. 2-K, distinguished by maximum sulfur content (0.04 and 0.30 percent of total mass, respectively), as well as all other grades of kerosene called range or stove oil. “Kerosene” does not include kerosene-type jet fuel.

(178) "Kiln" means an oven, furnace, or heated enclosure used for thermally processing a mineral or mineral-based substance.

(179) "Kilowatt hour" or "kWh" means the electrical energy unit of measure equal to one thousand watts of power supplied to, or taken from, an electric circuit steadily for one hour. (A watt is a unit of electrical power equal to one ampere under pressure of one volt, or 1/746 horsepower.)

(180) "Lead verifier" means a person that has met all of the requirements in section 95132(b)(2) and who may act as the lead verifier of a verification team providing verification services or as a lead verifier providing an independent review of verification services rendered.

(181) "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.

(182) "Less intensive verification" means the verification services provided in interim years between full verifications; less intensive verification of a reporting entity's emissions data report only requires data checks and document reviews of a reporting entity's emissions data report based on the analysis and risk assessment in the most current sampling plan developed as part of the most current full verification services. This level of verification may only be used if the verifier can provide findings with a reasonable level of assurance.

(183) "Linkage" means the approval of compliance instruments from an external greenhouse gas emission trading system (GHG ETS) to meet compliance obligations under the Cap-and-Trade Regulation, and the reciprocal approval of compliance instruments issued by California to meet compliance obligation in an external GHG ETS.

(184) "Linked jurisdiction" means a jurisdiction which has entered into a linkage agreement pursuant to subarticle 12 of the Cap-and-Trade Regulation.

(185) "Liquefied natural gas" or "LNG" means natural gas (primarily methane) that has been liquefied by reducing its temperature to -260 degrees Fahrenheit at atmospheric pressure.

(186) "Liquefied petroleum gas" or "LPG" means a flammable mixture of hydrocarbon gases used as a fuel. LPG can be mixtures of primarily propane, primarily butane, or mixtures of propane or butane. 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.

(187) “LNG boiloff gas” means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

(188) “Local distribution company” or “LDC,” for purposes of this article, means a company that owns or operates distribution pipelines, not interstate pipelines, that physically deliver natural gas to end users and includes public utility gas corporations, publicly-owned natural gas utilities and intrastate pipelines.

(189) “Lookback period” means the specified time period of historical data that the operators must use for missing data substitution as required by the regulation.

(190) “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 which is regulated by the process condition flows to a valve actuator controller where it vents (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

(191) “Low Btu gas” means gases recovered from casing vents, vapor recovery systems, crude oil and petroleum product storage tanks and other parts of the crude oil refining and natural gas production process.

(192) “Marketer” means a purchasing-selling entity that takes title to wholesale electricity and is not a retail provider.

(193) “Market-shifting leakage,” in the context of an offset project, means increased GHG emissions or decreased GHG removals outside an offset project’s boundary due to the effects of an offset project on an established market for goods or services.

(194) “Material misstatement” means an error, omission, or misreporting, or aggregation of the three, identified in the course of verification services that leads a verification team to believe that an emissions data report contains errors greater than 5 percent in the reported total CO_2e emissions. Material misstatement is calculated separately for each type of data as specified in section 95131(b)(13).

(195) “Maximum potential fuel flow rate” or “maximum fuel consumption rate” means the maximum fuel use rate the source is capable of combusting. When the source consists of multiple units, the maximum potential fuel use rate is the sum of the maximum potential fuel use rates of all the units aggregated as a source.

(196) “Megawatt hour” or “MWh” means the electrical energy unit of measure equal to one million watts of power supplied to, or taken from, an electric circuit steadily for one hour.

(197) “Methane” or “CH_4” means a GHG consisting on the molecular level of a single carbon atom and four hydrogen atoms.

(198) “Metric ton” or “MT” means a common international measurement for mass, equivalent to 2204.6 pounds or 1.1 short tons.

(199) “Missing data period” means a period of time during which a piece of data is not collected, is invalid, or is collected while the measurement device is not in compliance with the applicable quality-assurance requirements. In the context of periodic fuel sampling, missing data period is the entire sampling period (e.g. week, month, or quarter) for which corresponding fuel characteristic data are not obtained. In the context of periodic fuel consumption monitoring and recording, a missing data period consists of the consecutive time intervals (e.g. hours, days, weeks, or months) for which fuel consumption during the time period is not monitored and recorded.

(200) “MMBtu” means million British thermal units.

(201) “Motor gasoline” means a complex mixture of relatively volatile hydrocarbons with or without small quantities of additives, blended to form a fuel suitable for use in spark-ignition engines. Motor gasoline is characterized as having a boiling range of 122 to 158°F at the 10-percent recovery point to 365 to 374°F at the 90-percent recovery point.

(202) “Motor vehicle fuel” means gasoline. It does not include aviation gasoline, jet fuel, diesel fuel, kerosene, liquefied petroleum gas, natural gas in liquid or gaseous form, alcohol, or racing fuel.

(203) “Multi-jurisdictional retail provider” means a retail provider that provides electricity to consumers in California and in one or more other states in a contiguous service territory or from a common power system.

(204) “Municipal solid waste” or “MSW” means solid phase household, commercial/retail, and/or institutional waste, such as yard waste and refuse.

(205) “Nameplate generating capacity” means the maximum rated output of a generator under specific conditions designated by the manufacturer. Generator nameplate capacity is usually indicated in units of kilovolt-amperes (kVA) and in Kilowatts (kW) on a nameplate physically attached to the generator.

(206) “Naphthas” (< 401°F) is a generic term applied to a petroleum fraction with an approximate boiling range between 122°F and 400°F. The naphtha

fraction of crude oil is the raw material for gasoline and is composed largely of paraffinic hydrocarbons.

(207) "Natural gas" means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include methane, heavier hydrocarbons and carbon dioxide. Natural gas may be 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.

(208) "Natural gas distribution facility" means the distribution pipelines, metering stations, and regulating stations that are operated by a local distribution company (LDC) that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

(209) "Natural gas driven pneumatic pump" means a pump that uses pressurized natural gas to move a piston or diaphragm, which pumps liquids on the opposite side of the piston or diaphragm.

(210) "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 at lease separators and field facilities. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

(211) "Natural gas liquid fractionator" means an installation that fractionates natural gas liquids (NGLs) into their constituent liquid products (ethane, propane, normal butane, isobutene or pentanes plus) for supply to downstream facilities.

(212) "NERC E-tag" means North American Electric Reliability Corporation (NERC) energy tag representing transactions on the North American bulk electricity market scheduled to flow between or across balancing authority areas.

(213) "Net generation" or "net power generated" means the gross generation minus station service or unit service power requirements, 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.

(214) "Nitrous oxide" or "N_2O" means a GHG consisting at the molecular level of two nitrogen atoms and a single oxygen atom.

(215) “Nonconformance” means the failure to use the methods or emission factors specified in this article to calculate emissions, or the failure to meet any other requirements of the regulation.

(216) "Non-submitted/non-verified emissions data report" means an emissions data report that is not submitted to ARB by the applicable reporting deadline, or for which a verification statement has not been issued by the applicable verification deadline.

(217) “North American Industry Classification System (NAICS) code(s)” means the six-digit code(s) that represent the product(s)/activity(s)/service(s) at a facility or supplier as defined in North American Industrial Classification System Manual 2007, available from the U.S. Department of Commerce, National Technical Information Service.

(218) “Offset credit” means a tradable compliance instrument issued or approved by ARB that represents a GHG reduction or GHG removal enhancement of one metric ton of CO_2e. The GHG reduction or GHG removal enhancement must be real, additional, quantifiable permanent, verifiable and enforceable.

(219) “Offset project” means all equipment, materials, items, or actions that are directly related to or have an impact upon GHG reductions, project emissions or GHG removal enhancements within the offset project boundary.

(220) “Offset project boundary” is defined by and includes all GHG emission sources, GHG sinks or GHG reservoirs that are affected by an offset project and under control of the Offset Project Operator or Authorized Project Designee. GHG emissions sources, GHG sinks or GHG reservoirs not under control of the Offset Project Operator or Authorized Project Designee are not included in the offset project boundary.

(221) “Offset project data report” means the report prepared by an Offset Project Operator or Authorized Project Designee each year that provides the information and documentation required by this article or a compliance offset protocol.

(222) “Offset project operator” means the entity(ies) with legal authority to implement the offset project.

(223) “Offset protocol” means a documented set of procedures and requirements to quantify ongoing GHG reductions or GHG removal enhancements achieved by an offset project and calculate the project baseline. Offset protocols specify relevant data collection and monitoring procedures, emission factors and conservatively account for uncertainty and activity-shifting and market-shifting leakage risks associated with an offset project.

(224) "Offshore" means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act (43 U.S.C. §1331 et seq).

(225) "Offshore petroleum and natural gas production facility" means each platform structure and all associated equipment as defined in section 95150(a)(1) of this article.

(226) "Onshore petroleum and natural gas production facility" means all petroleum or natural gas equipment associated with all petroleum or natural gas production wells under common ownership or common control by an onshore petroleum and natural gas production owner or operator located in a single hydrocarbon basin as defined by the American Association of Petroleum Geologists which is assigned a three digit Geologic Province Code. Where an operating entity holds more than one permit in a basin, then all onshore petroleum and natural gas production equipment relating to all permits in their name in the basin is one onshore petroleum and natural gas production facility.

(227) "Onshore petroleum and natural gas production owner or operator" means the entity who is the permitee to operate petroleum and natural gas wells on the state drilling permit or a state operating permit where no drilling permit is issued by the state, which operates an onshore petroleum and/or natural gas production facility. Where more than one entity are permitees on the state drilling permit, or operating permit where no drilling permit is issued by the state, the permitted entities for the joint facility must designate one entity to report all emissions from the joint facility.

(228) "Operating pressure" means the containment pressure that characterizes the normal state of gas or liquid inside a particular process, pipeline, vessel or tank.

(229) "Operational control" for a facility subject to this article means the authority to introduce and implement operating, environmental, health and safety policies. In any circumstance where this authority is shared among multiple entities, the entity holding the permit to operate from the local air pollution control district or air quality management district is considered to have operational control for purposes of this article.

(230) "Operator" means the entity, including an owner, having operational control of a facility. For onshore petroleum and natural gas production, the operator is the operating entity listed on the state well drilling permit, or a state operating permit for wells where no drilling permit is issued by the state.

(231) "Other Biomass-Derived Fuel" means a biomass-derived fuel for which a reporting entity is required to hold a compliance obligation under title 17, California Code of Regulations, section 95852(g).

(232) "Outer Continental Shelf" means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in 43 U.S.C. § 1301, and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

(233) "Perfluorocarbons" or "PFCs" means a class of greenhouse gases consisting on the molecular level of carbon and fluorine.

(234) "Permanent" means, in the context of offset credits, either that GHG reductions or GHG removal enhancements are not reversible, or when GHG reductions or GHG removal enhancements may be reversible, that mechanisms are in place to replace any reversed GHG emission reductions or GHG removal enhancements to ensure that all credited reductions endure for a period that is comparable to the atmospheric lifetime of an anthropogenic CO_2 emission.

(235) "Petroleum" means oil removed from the earth and the oil derived from tar sands and shale.

(236) "Petroleum coke" means a black solid residue, obtained mainly by cracking and carbonizing of petroleum derived feedstocks, vacuum bottoms, tar and pitches in processes such as delayed coking or fluid coking. It consists mainly of carbon (90 to 95 percent), has low ash content, and may be used as a feedstock in coke ovens. This product is also known as marketable coke or catalyst coke.

(237) "Petroleum refinery" or "refinery" means any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives. Facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

(238) "Physical address," with respect to a United States parent company as defined in this section, means the street address, city, State and zip code of that company's physical location.

(239) "Pipeline quality natural gas" means natural gas having a high heat value greater than 970 Btu/scf and equal to or less than 1,100 Btu/scf, and which is at least ninety percent methane by volume, and which is less than five percent carbon dioxide by volume.

(240) "Point of delivery" 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.

(241) "Point of receipt" 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.

(242) "Point source" means any separately identifiable stationary point from which greenhouse gases are emitted.

(243) "Portable" means designed and capable of being carried or moved from one location to another. Indications of portability include wheels, skids, carrying handles, dolly, trailer, or platform. Equipment is not portable if any one of the following conditions exists:

(A) The equipment is attached to a foundation.

(B) The equipment or a replacement resides at the same location for more than 12 consecutive months.

(C) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility for at least two years, and operates at that facility for at least three months each year.

(D) The equipment is moved from one location to another in an attempt to circumvent the portable residence time requirements of this definition.

(244) "Portland cement" means hydraulic cement (cement that not only hardens by reacting with water but also forms a water-resistant product) produced by pulverizing clinkers consisting essentially of hydraulic calcium silicates, usually containing one or more of the forms of calcium sulfate as an inter-ground addition.

(245) "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.

(246) “Positive verification statement” means a verification 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 that the emissions data report conforms to the requirements of this article.

(247) “Power” means electricity, except where the context makes clear that another meaning is intended.

(248) “Power contract” means a written document arranging for the procurement of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.

(249) “Primary fuel” means the main fuel type (expressed in mmBtu) consumed by a unit for the applicable calendar year.

(250) “Prime mover” means the type of equipment such as an engine or water wheel that drives an electric generator. “Prime movers” include, but are not limited to, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

(251) “Process” means the intentional or unintentional reactions between substances or their transformation, including, but not limited to, the chemical or electrolytic reduction or metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

(252) “Process emissions” means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO_2 emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

(253) “Process gas” means any gas generated by an industrial process such as petroleum refining.

(254) “Process vent” means an opening where a gas stream is continuously or periodically discharged during normal operation.

(255) “Producer” means a person who owns, leases, operates, controls or supervises a California production facility.

(256) “Professional judgment” means the ability to render sound decisions based on professional qualifications and relevant greenhouse gas accounting and auditing experience.

(257) "Project baseline" means, in the context of a specific offset project, a conservative estimate of business-as-usual GHG emission reductions or GHG removal enhancements for the offset project's GHG emission sources, GHG sinks, or GHG reservoirs within the offset project boundary.

(258) "Propane" is a paraffinic hydrocarbon with molecular formula C_3H_8.

(259) "Public utility gas corporation" is a gas corporation defined in California Public Utilities Code section 222 that is also a public utility as defined in California Public Utilities Code section 216.

(260) "Publicly-owned natural gas utility" means a municipality or municipal corporation, a municipal utility district, a public utility district, or a joint powers authority that includes one or more of these agencies that furnishes natural gas services to end users.

(261) "Pump" means a device used to raise pressure, drive, or increase flow of liquid streams in closed or open conduits.

(262) "Pump seal emissions" means hydrocarbon gas released from the seal face between the pump internal chamber and the atmosphere.

(263) "Pump seals" means any seal on a pump drive shaft used to keep methane and/or carbon dioxide containing light liquids from escaping the inside of a pump case to the atmosphere.

(264) "Purchasing-selling entity" or "PSE" means the functional entity that purchases or sells, and takes title to energy, capacity, and reliability related services. A PSE is identified on a NERC E-tag for each physical path segment.

(265) "Pure" means consisting of at least 97 percent by mass of a specified substance. For facilities burning biomass fuels, this means the fraction of biomass carbon accounts for at least 97 percent of the total amount of carbon in the fuel burned at the facility.

(266) "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, but the emissions data report may include one or more nonconformance(s) with the requirements of this article which do not result in a material misstatement.

(267) "QA/QC" means quality assurance and quality control.

(268) "Quality-assured data" or "quality-assured value" means the data are obtained from a monitoring system that is operating within the performance specifications and the quality assurance/quality control procedures set forth

in the applicable rules, such as 40 CFR Part 60 or Part 75, without unscheduled maintenance, repair, or adjustment.

(269) “Quantifiable” means, in the context of offset projects, the ability to accurately measure and calculate GHG reductions or GHG removal enhancements relative to a project baseline in a reliable and replicable manner for all GHG emission sources, GHG sinks or GHG reservoirs included within the offset project boundary, while accounting for uncertainty, activity-shifting leakage and market-shifting leakage.

(270) “Rack” means a mechanism for delivering motor vehicle fuel or diesel from a refinery or terminal into a truck, trailer, railroad car, or other means of non-bulk transfer.

(271) “Real” means, in the context of offset projects, that GHG reductions or GHG enhancements result from a demonstrable action or set of actions, and are quantified using appropriate, accurate and conservative methodologies that account for all GHG emissions sources, GHG sinks, and GHG reservoirs within the offset project boundary and account for uncertainty and the potential for activity-shifting leakage and market-shifting leakage.

(272) “Reasonable assurance” means a high degree of confidence that submitted data and statements are valid.

(273) “Reciprocating compressor” means a piece of equipment that increases the pressure of a process natural gas by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

(274) “Recycled” refers to a material that is reused or reclaimed.

(275) “Reciprocating compressor rod packing” means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

(276) “Re-condenser” means heat exchangers that cool compressed boil-off gas to a temperature that will condense natural gas to a liquid.

(277) “Refinery fuel gas” or “still gas” means gas generated at a petroleum refinery or any gas generated by a refinery process unit, and that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

(278) “Reformulated Gasoline Blendstock for Oxygenate Blending” or “RBOB” has the same meaning as defined in title 13 of the California Code of Regulations, section 2260(a).

(279) "Relative Accuracy Test Audit" means a method of determining the correlation of continuous emissions monitoring system data to simultaneously collected reference method test data, such as required in 40 CFR Part 60 and 40 CFR Part 75.

(280) “Renewable diesel” means a motor vehicle fuel or fuel additive that is all of the following:

(A) Registered as a motor vehicle fuel or fuel additive under 40 CFR Part 79;

(B) Not a mono-alkyl ester;

(C) Intended for use in engines that are designed to run on conventional diesel fuel; and

(D) Derived from nonpetroleum renewable resources.

(281) “Renewable energy” means energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

(282) “Reporting entity” means a facility operator, supplier, or electric power entity subject to the requirements of this article.

(283) “Reporting period” means the calendar year which coincides with the data year for the GHG report.

(284) “Reporting year” or “report year” means data year.

(285) “Reservoir” means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases. A reservoir is characterized by a single natural pressure system.

(286) “Residual fuel oil” means a general classification for the heavier oils, known as No. 5 and No. 6 fuel oils, that remain after the distillate fuel oils and lighter hydrocarbons are distilled away in refinery operations.

(287) “Retail provider” means an entity that provides electricity to retail end users in California and is an electric corporation as defined in Public Utilities Code section 218, electric service provider as defined in Public Utilities Code section 218.3, local publicly owned electric utility as defined in Public Utilities Code section 224.3, a community choice aggregator as defined in Public Utilities Code section 331.1, or the Western Area Power Administration. For purposes of this article, electrical cooperatives, as defined by Public Utilities Code section 2776, are excluded.

(288) "Retail sales" means electricity sold to retail end users.

(289) "Retail end-use customer" or "retail end user" means a residential, commercial, agricultural, or industrial electric customer who buys electricity to be consumed as a final product and not for resale.

(290) "Sales oil" means produced crude oil or condensate measured at the production lease automatic custody transfer (LACT) meter or custody transfer meter tank gauge.

(291) "Sector" means a broad industrial categorization such as specified in section 95101.

(292) "Sector-based offset credit" means a credit issued from a sector-based crediting program once the crediting baseline for a sector has been reached. For the limited purposes of this definition, "sector" means a group or subgroup of an economic activity - or a group of economic activities - as in "service sector" - or a cross-section of a group of economic activities - as in "informal sector."

(293) "Sector-based crediting program" is a GHG emissions reduction crediting mechanism established by a country, region, or subnational jurisdiction in a developing country and covering a particular economic sector within that jurisdiction. A program's performance is based on achievement toward an emissions reduction target for the particular sector within the boundary of the jurisdiction and beyond. Responsibility for reducing emissions in a sector-based crediting program is shared between GHG mitigation policies and activities specific to that sector that exceed legal requirements and market mechanisms. For the limited purposes of this definition, "sector" means a group or subgroup of an economic activity - or a group of economic activities - as in "service sector" - or a cross-section of a group of economic activities - as in "informal sector."

(294) "Separator" means a vessel in which streams of multiple phases are gravity separated into individual streams of single phase.

(295) "Short ton" means a common international measurement for mass, equivalent to 2,000 pounds.

(296) "Shutdown" means the cessation of operation of an emission source for any purpose.

(297) "Sour natural gas" means natural gas that contains significant concentrations of hydrogen sulfide and/or carbon dioxide that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

(298) “Source” means greenhouse gas source; any physical unit, process, or other use or activity that releases a greenhouse gas into the atmosphere.

(299) “Specified source of electricity” or “specified source” means a facility or unit which is permitted to be claimed as the source of imported electricity delivered by an electricity importer. The electricity importer must have either full or partial ownership in the facility/unit or a written contract to procure electricity generated by that facility/unit. Specified facilities/units include cogeneration systems. Specified source also means electricity procured from an asset-controlling supplier recognized by the ARB.

(300) “Standard cubic foot” or “scf” is a measure of quantity of gas, equal to a cubic foot of volume at 60 degrees Fahrenheit and either 14.696 pounds per square inch (1 atm) or 14.73 PSI (30 inches Hg) of pressure.

(301) “Standard conditions” or “standard temperature and pressure (STP)” means 68 degrees Fahrenheit and 14.7 pounds per square inch absolute.

(302) “SSM” means periods of startup, shutdown and malfunction during flare operations.

(303) “Stationary” means neither portable nor self propelled, and operated at a single facility.

(304) “Storage tank” means any tank, other container, or reservoir used for the storage of organic liquids, excluding tanks that are permanently affixed to mobile vehicles such as railroad tank cars, tanker trucks or ocean vessels.

(305) “Substitute power” or “substitute electricity” means electricity that is provided to meet the terms of a power purchase contract with a specified facility or unit when that facility or unit is not generating electricity.

(306) “Sulfur hexafluoride” or ”SF_6” means a GHG consisting on the molecular level of a single sulfur atom and six fluorine atoms.

(307) “Supplemental firing” means an energy input to the cogeneration facility used only in the thermal process of a topping-cycle plant, or in the electric generating or manufacturing process of a bottoming-cycle cogeneration facility.

(308) “Supplier” means a producer, importer, or exporter of a fossil fuel or an industrial greenhouse gas.

(309) “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.

(310) “Tactical support equipment” is as defined in Title 17, California Code of Regulations, section 93116.2(a)(36).

(311) “Terminal” means a motor vehicle fuel or diesel fuel storage and distribution facility that is supplied by pipeline or vessel, and from which motor vehicle fuel may be removed at a rack. “Terminal” includes a fuel production facility where motor vehicle fuel is produced and stored and from which motor vehicle fuel may be removed at a rack.

(312) “Terminal Operator” means any entity that owns, operates or otherwise controls a terminal that is supplied by pipeline or vessel and from which accountable fuel products may be removed at a rack.

(313) “Thermal energy” means the thermal output produced by a combustion source used directly as part of a manufacturing process but not used to produce electricity.

(314) “Tier” means the level of calculation method from 40 CFR §98.33 that is required for a stationary combustion source in section 95115 of this article.

(315) “Tier 1” means a stationary combustion calculation method that applies default values for emission factors and high heat value to generate an emissions estimate, as specified in 40 CFR §98.33.

(316) “Tier 2” means a stationary combustion calculation method that applies a default value for an emission factor and a fuel’s measured high heat value (or a boiler efficiency for steam-generating solid fuels) to generate an emissions estimate, as specified in 40 CFR §98.33.

(317) “Tier 3” means a stationary combustion calculation method that utilizes a fuel’s measured carbon content to generate an emissions estimate, as specified in 40 CFR §98.33.

(318) “Tier 4” means a stationary combustion calculation method that utilizes quality-assured data from a continuous emission monitoring system to generate an emissions estimate, as specified in 40 CFR §98.33. This method may also capture process emissions from a common stack.

(319) “Topping cycle” means a type of cogeneration system in which the energy input to the plant is first used to produce electricity, and at least some of the reject heat from the electricity production process is then used to provide useful thermal output.

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

(321) “Tribal nation” means those Native American tribes in the United States and listed in the Federal Register.

(322) “Turbine meter” means a flow meter in which a gas or liquid flow rate through the calibrated tube spins a turbine from which the spin rate is detected and calibrated to measure the fluid flow rate.

(323) “Uncertainty” means the degree to which data or a data system is deemed to be indefinite or unreliable.

(324) “Uncontrolled blowdown system” means the use of a blowdown procedure that does not result in the recovery of emissions for flaring or re-injection.

(325) “Unconventional wells” means gas wells in producing fields that employ hydraulic fracturing to enhance gas production volumes.

(326) “United States” means the 50 States, the District of Columbia, the Commonwealth of Puerto Rico, American Samoa, the Virgin Islands, Guam, and any other Commonwealth, territory or possession of the United States, as well as the territorial sea as defined by Presidential Proclamation No. 5928.

(327) “United States parent company(s)” mean the highest-level United States company(s) with an ownership interest in the reporting entity as of December 31 of the reporting year.

(328) “Unspecified source of electricity” or “unspecified source” means electricity generation that cannot be matched to a specific facility or unit that generates electricity or matched to an asset-controlling supplier recognized by the ARB. Unspecified sources contribute to the bulk system power pool and typically are dispatchable, marginal resources that do not serve baseload.

(329) “U.S. EPA” means the United States Environmental Protection Agency.

(330) “Useful thermal output” means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

(331) “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.

(332) “Vaporization unit” means a process unit that performs controlled heat input to vaporize LNG to supply transmission and distribution pipelines or consumers with natural gas.

(333) “Variable renewable resource” means run-of-river hydroelectric, solar, or wind energy that requires firming and shaping to meet load requirements.

(334) “Vented emissions” means intentional or designed releases of CH_4 or CO_2 containing natural gas or hydrocarbon gas (not including stationary combustion flue gas), including process designed flow to the atmosphere through seals or vent pipes, equipment blowdown for maintenance, and direct venting of gas used to power equipment (such as pneumatic devices).

(335) “Verifiable,” in the context of offset projects, means that an offset project data report assertion is well documented and transparent such that it lends itself to an objective review by an accredited verification body.

(336) “Verification” means a systematic, independent and documented process for evaluation of a reporting entity’s emissions data report against ARB’s reporting procedures and methods for calculation and reporting GHG emissions.

(337) “Verification body” means a firm accredited by ARB that is able to render a verification statement and provide verification services for reporting entities subject to reporting under this article.

(338) “Verification services” means services provided during verification as specified in section 95131 beginning with the development of the verification plan or first site visit, including but not limited to reviewing a reporting entity’s emissions data report, verifying its accuracy according to the standards specified in this article, assessing the reporting entity’s compliance with this article, and submitting a verification statement to the ARB.

(339) “Verification statement” means the final statement rendered by a verification body attesting whether a reporting entity’s emissions data report is free of material misstatement, and whether the emissions data report conforms to the requirements of this article.

(340) “Verification team” means all of those working for a verification body, including all subcontractors, to provide verification services for a reporting entity.

(341) “Verified emissions data report” means an emissions data report that has been reviewed by a third-party verifier and has a verification statement accepted by the ARB.

(342) "Verifier" means an individual accredited by ARB to carry out verification services as specified in section 95131.

(343) "Verifier review" means a verifier conducts all reviews and services in section 95131, except the material misstatement assessment under section 95131(b)(14). If some of the sources are selected for data checks based on the sampling plan, the verifier will check for conformance with the requirements of this article.

(344) "Volatile organic compound" or "VOC" means any volatile compound of carbon, excluding carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate, which participates in atmospheric photochemical reactions.

(345) "Weighted monthly average" means the sum of the products of two values measured during the same time period divided by the sum of the values not being averaged. For weighted average HHV it would be the sum of the products of volume and HHV measured during the same time period divided by the sum of the volumes.

(346) "Well completions" means a process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics. This process includes high-rate back-flow of injected water and sand used to fracture and prop-open fractures in low permeability gas reservoirs.

(347) "Well workover" means the performance of one or more of a variety of remedial operations on producing oil and gas wells to try to increase production. This process also includes high-rate back-flow of injected water and sand used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs.

(348) "Wellhead" means the piping, casing, tubing and connected valves protruding above the Earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve.

(349) "Wet natural gas" means natural gas in which water vapor exceeds the concentration specified for commercially saleable natural gas delivered from transmission and distribution pipelines. This input stream to a natural gas dehydrator is referred to as "wet gas".

(350) "Wholesale sales" means sales to other LDCs.

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

(a) *Abbreviated Reporting for Facilities with Emissions Below 25,000 Metric Tons of CO_2e.* The facility operator without a compliance obligation under the Cap-and-Trade Regulation during any year of the current three-year compliance period, who is also not subject to the reporting requirements of 40 CFR Part 98 and whose total stationary and process emissions are below 25,000 metric tons of CO_2e in 2011 and each subsequent year, may submit abbreviated emissions data reports under this article. This provision does not apply to suppliers or electric power entities. Abbreviated reports must include the following information:

(1) Facility name, assigned ARB identification number, physical street address including the city, state and zip code, air basin, air district, county, and geographic location.

(2) Total facility GHG emissions aggregated for all stationary fuel combustion units and calculated according to any method available by fuel type in 40 CFR §98.33(a), expressed in metric tons of total CO_2, CO_2 from biomass-derived fuels, CH_4, and N_2O.

(3) If applicable, GHG emissions for each process source type found in 40 CFR Part 98 that was in operation at the facility during the period covered by the report. Emissions must be determined according to any method specified for that process emissions type in 40 CFR Part 98, and expressed in metric tons of CO_2, CO_2 from bio-based feedstock, CH_4, N_2O, and total CO_2e as applicable. At facilities where a continuous emissions monitoring system (CEMS) is installed and operated according to federal, state or local requirements, process emissions may be reported in combination with stationary combustion emissions, but fuel use by fuel type must be separately reported in the units specified below.

(4) Identification of the methods chosen for determining emissions.

(5) 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.

(6) For facilities with on-site electricity generation or cogeneration, the information specified in section 95112(a)-(b) of this article.

(7) 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).

(b) Abbreviated emissions data reports submitted under this provision must be certified no later than June 1 of each calendar year. 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_2e emissions, or if error correction would cause the emissions total to exceed 25,000 metric tons of CO_2e, in which case a report that meets the full requirements of this article must be submitted.

(c) 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.

(d) An abbreviated emissions data report is not subject to the third-party verification requirements of this article.

(e) *Reporting Deadlines.* Except as otherwise specified in this paragraph, each facility operator or supplier must submit an emissions data report for the previous calendar year no later than April 1 of each calendar year. Each electric power entity must submit an emissions data report for the previous calendar year no later than June 1 of each calendar year. The operator submitting an abbreviated report under the provisions of section 95103(a)-(d) must submit the abbreviated report no later than June 1 of each calendar year.

(f) *Verification Requirement and Deadlines.* 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, and each reporting entity that has or has had a compliance obligation under the Cap-and-Trade Regulation in any year of the current three-year compliance period, 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 a verification statement submitted by the verification body to the Executive Officer by September 1 each year for operators and suppliers, and by October 1 each year for electric power entities. Each reporting entity must ensure that this verification statement is submitted by the applicable deadline specified in this paragraph. Contracting with a verification body without providing sufficient time to complete the verification statement 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).

(g) *Non-submitted/Non-verified Emissions Data Reports*. When a reporting entity that holds a compliance obligation under the Cap-and-Trade Regulation fails to submit an emissions data report or fails to obtain a positive or qualified positive verification statement by the applicable deadline, the Executive Officer shall develop an assigned emissions level for the reporting entity as set forth in section 95131(c)(5)(A)-(B).

(h) *Reporting in 2012.* For emissions data reports due in 2012, in cases where monitoring equipment and procedures were not in place in 2011 to enable reporting under the full specifications of this article, operators and suppliers must report 2011 emissions using monitoring and calculation methods that are applicable to them from 40 CFR Part 98. Electric power entities must report 2011 electricity transactions (MWh) and emissions (MT of CO_2e) under the full specifications of this article as applicable in 2012.

(i) *Calculation and Reporting of* De Minimis *Emissions*. A facility operator may designate as *de minimis* a portion of GHG emissions, representing no more than 3 percent of a facility's total CO_2 equivalent emissions (including emissions from biomass-derived fuels and feedstock), not to exceed 20,000 metric tons of CO_2e. The operator may estimate *de minimis* emissions using alternative methods of the operator's choosing, subject to the concurrence of the verification body that the methods used are reasonable, not biased toward significant underestimation or overestimation of emissions, and unlikely to exceed the *de minimis* limits. Where these emissions are required to be reported by 40 CFR Part 98, the operator must calculate and report them consistent with the report submitted to U.S. EPA under those requirements. The operator must separately identify and include in the emissions data report the emissions from designated *de minimis* sources. The operator must determine CO_2 equivalence according to the global warming potentials provided in Table A-1 of 40 CFR Part 98.

(j) *Calculating, Reporting, and Verifying Emissions from Biomass-Derived Fuels.* The operator or supplier must separately identify, calculate, and report all direct emission of CO_2 resulting from the combustion of biomass-derived fuels as specified in sections 95115 for facilities, and sections 95121-95122 for suppliers. Biomass-derived fuel emissions must be identified by the source of fuel as described in title 17, California Code of Regulations, section 95852.2. A biomass-derived fuel not listed in that section will be identified as an Other Biomass-Derived Fuel and the reporting entity will be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852.1. For a fuel listed under title 17, California Code of Regulations, section 95852.2, reporting entities must also meet the verification requirements in section 95131(i) of this article, or the fuel must be identified as an Other Biomass-Derived Fuel and be subject to a compliance obligation under title 17, California Code of Regulations, section 95852.1. 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.

(k) *Measurement Accuracy Requirement*. The operator or supplier submitting an emissions data report with fossil fuel emissions greater than or equal to 25,000 metric tons of CO_2e, and each operator or supplier with a compliance obligation under the Cap-and-Trade Regulation in any year of the current three-year compliance period, must meet the requirements of 40 CFR §98.3(i) for calibration and measurement device accuracy. The operator or supplier with infrequent outages as specified at 40 CFR §98.3(i)(6) who documents in the monitoring plan a calibration postponement after January 1, 2012 must submit to the Executive Officer a request for postponement, within 30 days of the postponement or the effective date of this article, whichever occurs last. The request must include an explanation of the reasons for the postponement, the date when the calibration will be completed, or a demonstration of meter accuracy in the absence of calibration. Such postponement will be subject to the approval of the Executive Officer.

(l) *Weekly Fuel Monitoring.* In addition to the requirements specified in 40 CFR §98.3(g)(5), as a part of the GHG Monitoring Plan the operator must monitor fuel measurement equipment and maintain records of its proper operation by recording fuel consumption quantities at least weekly, where such equipment is used to calculate GHG emissions. The records of fuel consumption must be sufficient for the application of the missing data substitution procedure in section 95129(d)(2) in the event that the use of that procedure becomes necessary.

(m) *Changes in Methodology*. Except as specified below, where this article permits a choice between different methods for the monitoring and calculation of GHGs, the operator or supplier must make this choice by January 1, 2013, and continue to use the method chosen for all future emissions data reports, unless the use of an alternative calculation method is approved in advance by the Executive Officer.

(1) The operator or supplier is permitted to permanently improve the emissions calculation method after January 1, 2013 through a change to a higher-tier monitoring or calculation method, such as the addition of a continuous emissions monitoring system.
(2) The operator or supplier is permitted to temporarily modify the emissions monitoring or calculation method when consistent with and necessary to comply with the missing data provisions of this article.
(3) When proposing a change in monitoring or calculation method, an operator or supplier must indicate why the change in method is being proposed, and provide a demonstration of differences in estimated emissions under the two methods.
(4) When permitted, a change in method must be made after the completion of monitoring for a data year, and not for a portion of a data year except where necessary to comply with section 95129 and other missing data substitution provisions of this article.

(n) *Addresses*. The following address shall be substituted for the addresses provided in 40 CFR §98.9 for both U.S. mail and package deliveries:

Executive Officer
Attn: Emission Inventory Branch
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

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

§ 95104. Emissions Data Report Contents and Mechanism.

The reporting entities specified in 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.

(b) *Designated Representative.* Each reporting entity must designate a reporting representative and adhere to the requirements for this representative at 40 CFR §98.4. Operators and suppliers with a reporting obligation under 40 CFR Part 98 must designate the same reporting representative as named under those requirements.

(c) *Corporate Parent and NAICS Codes*. Each reporting entity must submit information to meet the requirements specified in amendments to 40 CFR Part 98 on Reporting of Corporate Parent Information, NAICS Codes and Cogeneration, as promulgated by U.S. EPA on September 22, 2010.

(d) *Energy Purchases.* The operator must include in the emissions data report the facility's electricity purchases (kWh), and steam, heat, and cooling purchases (mmBtu), each by name and ARB identification number of the provider. The operator must report this information for the calendar year covered by the emissions data report, pro-rating purchases as necessary to include information for the full months of January and December.

(e) *Reporting Mechanism*. Reporting entities shall submit emissions data reports, and any revisions to the reports, through the California Air Resources Board's (ARB) Greenhouse Gas Reporting Tool, or any other reporting tool approved by the Executive Officer that will guarantee transmittal and receipt of data required by ARB's Mandatory Reporting Regulation and Cost of Implementation Fee Regulation.

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

§ 95105. Recordkeeping Requirements.

Each reporting entity that is required to report greenhouse gases under this article, except as provided in section 95103(c), must keep records as required by 40 CFR §98.3(g)-(h) with the following qualifications.

(a) *Duration*. Reporting entities with a compliance obligation under the Cap-and-Trade Regulation in any year of the current three-year compliance period must maintain all records specified in 40 CFR §98.3(g), and records associated with revisions to emissions data reports as provided under 40 CFR §98.3(h), for a period of ten years from the date of emissions data report certification. The retained documents, including GHG emissions data and input data, must be sufficient to allow for verification of each emissions data report. Reporting entities that do not have a compliance obligation under the Cap-and-Trade Regulation during any year of the current three-year compliance period must maintain such records for a period of five years from the date of certification.

(b) *ARB Requests for Records*. Copies of any records or other materials maintained under the requirements of 40 CFR Part 98 or this article must be made available to the Executive Officer upon request, within twenty days of receipt of such request by the designated representative of the reporting entity.

(c) *GHG Monitoring Plan*. Each reporting entity that reports under 40 CFR Part 98, and each reporting entity with a compliance obligation under the Cap-and-Trade Regulation in any year of the current three-year 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) and includes the following elements:

(1) All fuel use measurement devices used for emissions calculations must be clearly identified, and the plan must indicate how data from these devices are incorporated into the emissions data report;
2) Original equipment manufacturer (OEM) documentation, or other documentation that identifies instrument accuracy and required maintenance and calibration requirements for all measurement devices used in the calculation of GHG emissions.
(3) Training practices for personnel involved in GHG monitoring, including documented training procedures, and training materials;
(4) Copies of methodologies used for all fuel analyses.

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

§ 95106. Confidentiality.

(a) Emissions data submitted to the ARB under this article is public information and shall not be designated as confidential. Data reported to U.S. EPA under 40 CFR Part 98 which is determined to be non-confidential by U.S. EPA shall be considered public information by ARB.

(b) Any entity submitting information to the Executive Officer pursuant to this article may claim such information as "confidential" by clearly identifying such information as "confidential." Any claim of confidentiality by an entity submitting information must be based on the entity's belief that the information marked as confidential is either trade secret or otherwise exempt from public disclosure under the California Public Record Act (Government Code, section 6250 et seq.). All such requests for confidentiality shall be handled in accordance with the procedures specified in California Code of Regulations, title 17, sections 91000 to 91022.

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

§ 95107. Enforcement.

(a) Each day or portion thereof that any report required by this article remains unsubmitted, is submitted late, or contains information that is incomplete or inaccurate within the level of reproducibility of a test or measurement method is a separate violation. For purposes of this section, "report" means any emissions data report, verification statement, or other record required to be submitted to the Executive Officer by this article.

(b) Except as otherwise provided in this section, each day or portion thereof in which any other violation of this article occurs is a separate offense.

(c) Each metric ton of CO_2e emitted but not reported as required by this article is a separate violation.

(d) Each failure to measure, collect, record or preserve information needed for the calculation of emissions as required by this article or that this article otherwise requires be measured, collected, recorded or preserved constitutes a separate violation of this article.

(e) The Executive Officer may revoke or modify any Executive Order issued pursuant to this article as a sanction for a violation of this article.

(f) The violation of any condition of an Executive Order that is issued pursuant to this article is a separate violation.

(g) Penalties may be assessed for any violation of this article pursuant to Health and Safety Code section 38580.

(h) Any violation of this article may be enjoined pursuant to Health and Safety Code section 41513.

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

§ 95108. Severability.

Each part of this article shall be deemed severable, and in the event that any provision of this article is held to be invalid, the remainder of this article shall continue in full force and effect.

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

§ 95109. Standardized Methods.

(a) Entities that are required to report greenhouse gas emissions pursuant to this article must use either those standardized methods and materials listed in 40 CFR §98.7, or another similar method published by an organization listed in 40 CFR §98.7 that is applicable to the analysis being conducted. For gaseous fuels, fuel characteristics may be determined using chromatographic analysis as specified in 40 CFR §98.34(a)(6) and §98.34(b)(5). All methods used must be documented in the GHG Monitoring Plan that is as required by section 95105(c).

(b) Alternative test methods that are demonstrated to the satisfaction of the Executive Officer to be equally or more accurate than the methods in section 95109(a) may be used upon written approval by the Executive Officer.

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

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

§ 95110. Cement Production.

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 comply with Subpart H of 40 CFR Part 98 (§§98.80 to 98.88) in reporting annual stationary combustion and process emissions from cement production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, 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.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95110(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95110(c), 95115, and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.85 when substituting for missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If data for the carbonate content of clinker or cement kiln dust as required by 40 CFR §98.83(d) are missing, and a new analysis cannot be undertaken, the operator must apply a substitute value according to the procedures in paragraphs (A)-(C) below.

(A) If the data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(3) For each missing value of the monthly raw material consumption or monthly clinker production, the operator must apply a substitute value according to paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.85(c) or 40 CFR §98.85(d), as applicable.
(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum tons of clinker per day capacity of the system or the maximum tons per day raw material throughput of the kiln, as applicable, and the number of days per month.

(4) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Data to Support Benchmarking.* In addition to the information required by 40 CFR §98.86, the operator must report the additional parameters provided in paragraphs (1)-(2) below whether or not a CEMS is used to measure CO_2 emissions.

(1) Annual quantity of clinker substitute consumed for blending, by type (short tons).
(2) Annual quantity of cement substitute consumed, by type (short tons).

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

§ 95111. Data Requirements and Calculation Methods for Electric Power Entities.

Any electric power entity who is required to report under section 95101 of this article must comply with the following requirements when reporting to ARB.

(a) *General Requirements and Content for GHG Emissions Data Reports for Electricity Importers and Exporters.*

(1) *Greenhouse Gas Emissions.* The electric power entity must report GHG emissions separately for each category of delivered electricity required, in metric tons of CO_2 equivalent (CO_2e), according to the calculation methods in section 95111(b).

(2) *Delivered Electricity.* The electric power entity must report delivered electricity in MWh, and must also separately report all imported electricity from

unspecified sources by first point of receipt, and all imported electricity from each specified source.

(3) *Imported Electricity from Unspecified Sources.* When reporting imported electricity from unspecified sources, the electric power entity must aggregate electricity deliveries and associated GHG emissions by first point of receipt. The electric power entity also must report the following:

(A) The standardized acronym or code and the full name for the first point of receipt and the jurisdiction in which it is located;
(B) The amount of electricity from unspecified sources as measured at the first point of delivery in California; and,
(C) Whether transmission losses are made up in other electricity deliveries reported or from California sources. Transmission losses must be reported as required in section 95111(b).

(4) *Imported Electricity from Specified Facilities or Units.* When reporting imported electricity from specified facilities or units, the electric power entity must aggregate electricity deliveries and associated GHG emissions by facility or unit, as applicable.

(A) If the electric power entity holds a contract for a specified percentage of a facility's or unit's generation in the report year, the electric power entity must include electricity purchased or sold as being from a partially or fully owned facility or unit and meet the same requirements for partially or fully owned facilities or units in this section.
(B) Claims of specified sources of imported electricity must meet the requirements in section 95111(g) and include the following information:

1. Total facility or unit gross and net generation;
2. For specified deliveries from facilities or units that report GHG emissions to ARB or to U.S. EPA pursuant to 40 CFR Part 98, whether GHG emissions associated with net power generated exceed 1100 lbs CO_2e/MWh;
3. The amount of imported electricity from specified facilities or units as measured at the busbar; and
4. For imported electricity deliveries from specified facilities or units where measurements at the busbar are not known, the amount of imported electricity as measured at the first point of delivery in California and estimated transmission losses as required in section 95111(b). The electric power entity also must report whether transmission losses are made up in other imported electricity deliveries reported, or from California sources.

(5) *Imported Electricity from Asset-Controlling Suppliers.* The electric power entity must separately report imported electricity supplied by asset-controlling

suppliers recognized by ARB. Each asset-controlling supplier must be identified on the NERC E-tags as the PSE at the first point of receipt. The electric power entity must:

(A) Report the asset-controlling supplier standardized acronym or code, full name, and the ARB identification number;
(B) Report delivered electricity as specified and not as unspecified;
(C) Report delivered electricity from asset-controlling suppliers as measured at the first point of delivery in the state of California; and,
(D) Report GHG emissions calculated pursuant to section 95111(b).

(6) *Imported Electricity from Multi-jurisdictional Retail Providers.* The electric power entity must separately report imported electricity supplied by multi-jurisdictional retail providers who are recognized by the ARB as asset-controlling suppliers. Multi-jurisdictional retail providers are recognized by the ARB as asset-controlling suppliers when their system power emission factor, calculated and published on the ARB Mandatory Reporting website, is greater than 1100 lbs CO_2e/MWh.

(A) The electric power entity must report imported electricity supplied by multi-jurisdictional retail providers as measured at the first point of delivery in California.
(B) Multi-jurisdictional retail providers must report retail sales in their California service territory as imported electricity.
(C) The electric power entity must report GHG emissions calculated pursuant to section 95111(b). For multi-jurisdictional retail providers recognized by ARB as an asset-controlling suppliers, refer to subsection 95111(b)(3) and 95111(b)(4).

(7) *Exported Electricity.* The electric power entity must report exported electricity in MWh and associated GHG emissions in MT of CO_2e aggregated by each final point of delivery outside the state of California, as well as the following information:

(A) For each final point of delivery outside the state of California, include the standardized acronym or code, full name, and the jurisdiction in which it is located.
(B) Exported electricity as measured at the last point of delivery located in the state of California, if known. If unknown, report as measured at the final point of delivery outside California.
(C) Do not report estimated transmission losses.
(D) Report zero MT of CO_2e for each final point of delivery published on the ARB Mandatory Reporting website as located in a linked jurisdiction.
(E) For other final points of delivery, report associated emissions for each point by multiplying MWh exported by the emission factor calculated and

published on the ARB Mandatory Reporting website for unspecified imported electricity.

(8) *Exchange Agreements.* The electric power entity must report delivered electricity under power exchange agreements consistent with imported and exported electricity requirements of this section. Electricity delivered into the state of California under exchange agreements must be reported as imported electricity and electricity delivered out of California under exchange agreements must be reported as exported electricity.

(9) *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.

(10) *Verification Documentation.* The electric power entity must retain for purposes of verification NERC E-tags, written contracts, settlements data, and all other information needed to confirm reported electricity procurements and deliveries pursuant to the recordkeeping requirements of section 95105.

(11) *Electricity Generating Units and Cogeneration in California.* Electric power entities that also operate electricity generating units or cogeneration located inside the state of California that meet the applicability requirements of this article must report GHG emissions to ARB under section 95112.

(12) *Electricity Generating Units and Cogeneration Outside California.* Operators and owners of electricity generating units and cogeneration located outside the state of California who elect to report to ARB under section 95112 must fully comply with the reporting and verification requirements of this article.

(b) Calculating GHG Emissions.

(1) *Calculating GHG Emissions from Unspecified Sources.* For electricity from unspecified sources, the electric power entity must calculate the annual CO_2 equivalent mass emissions using the following equation:

$$CO_2e = MWh \times TL \times EF_{unsp}$$

Where:

CO_2e = Annual CO_2 equivalent mass emissions from the unspecified electricity deliveries at each point of receipt identified (metric tons).

MWh = Megawatt-hours of unspecified electricity deliveries at each point of receipt identified.

EF_{unsp} = Default emission factor for unspecified electricity imports calculated and published on the ARB Mandatory Reporting website .

EF_{unsp} = 0.435 MT of CO_2e/MWh for first points of receipt located in non-linked jurisdictions.

EF_{unsp} = 0 MT of CO_2e/MWh for points of receipt located in linked jurisdictions.
TL = Transmission loss correction factor.
TL = 1.02 when transmission losses are not made up in other electricity deliveries reported or from California sources.
TL = 1.0 when transmission losses are made up in other electricity deliveries reported or from California sources.

(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 (metric tons).
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. EF_{sp} = 0 MT of CO_2e for facilities located in linked jurisdictions and facilities, or units within facilities, below the GHG emissions compliance threshold for delivered electricity pursuant to the Cap-and-Trade Regulation
TL = Transmission loss correction factor.
TL = 1.02 when deliveries are not reported as measured at the busbar, and transmission losses are not made up in other electricity deliveries reported or from California sources.
TL = 1.0 when deliveries are reported as measured at the busbar, or transmission losses are made up in other electricity deliveries reported or from California sources.

The Executive Officer shall calculate facility-specific or unit-specific emission factors and publish them on the ARB Mandatory Reporting website using the following equation:

$$EF_{sp} = E_{sp} / EG$$

Where:
E_{sp} = CO_2e emissions for a specified facility or unit for the report year (MT of CO_2e).
EG = Net generation from a specified facility or unit for the report year reported to ARB under this section (MWh).

(A) For specified facilities or units whose operators are subject to this article or whose owners or operators voluntarily report under this article, E_{sp}

shall be equal to the sum of CO_2e emissions from stationary combustion of fossil fuels, acid gas scrubbers, or acid gas reagents, as reported to ARB.

(B) For specified facilities or units whose operators are not subject to reporting under this article or whose owners or operators do not voluntarily report under this article, but are subject to the U.S. EPA GHG Mandatory Reporting Regulation, E_{sp} shall be equal to the sum of CO_2e emissions reported to U.S. EPA pursuant to 40 CFR Part 98.

(C) For specified facilities or units whose operators are not subject to reporting under this article or whose owners or operators do not voluntarily report under this article, nor are subject to the U.S. EPA GHG Mandatory Reporting Regulation, E_{sp} is calculated using heat of combustion data reported to the Energy Information Administration (EIA) as shown below.

$$E_{sp} = 0.001 \times \Sigma(Q_{fuel} \times EF_{fuel})$$

Where:

Q_{fuel} = Heat of combustion for each specified fuel type from the specified facility or unit for the report year (MMBtu). For cogeneration, Q_{fuel} is the quantity of fuel allocated to electricity generation consistent with EIA reporting.

EF_{fuel} = CO_2e emission factor for the specified fuel type as required by this article (kg CO_2e /MMBtu).

(D) New facilities or units will be assigned an emission factor by the ARB based on the type of fuel combusted or the technology for the first year of reporting when a U.S. EPA GHG Report or EIA fuel consumption report is not available for the previous report year.

(3) *Calculating GHG Emissions of Imported Electricity from Specified Asset-Controlling Suppliers.* ARB will calculate and publish on the ARB Mandatory Reporting website system emission factors for the following asset-controlling suppliers: Bonneville Power Administration, multi-jurisdictional retail providers, and asset-controlling suppliers with a system emission factor greater than 1100 lbs CO_2e/MWh. For imported electricity from asset-controlling suppliers recognized by the ARB, the electric power entity must calculate emissions 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 each supplier identified (metric tons).

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 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, beginning in the 2010 data year and meeting the requirements for asset-controlling suppliers.

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 and transmission losses are not made up in other electricity deliveries reported or from California sources.

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 or transmission losses are made up in other electricity deliveries reported or from California sources.

The Executive Officer shall calculate the system emission factor for asset-controlling suppliers using the following equations:

EF_{ACS} = Sum of System Emissions MT of CO_2e / Sum of System MWh

$$\text{Sum of System Emissions, MT of } CO_2e = \Sigma E_{asp} + \Sigma(PE_{sp} * EF_{sp}) + \Sigma(PE_{unsp} * EF_{unsp}) - \Sigma(SE_{sp} * EF_{sp})$$

$$\text{Sum of System MWh} = \Sigma EG_{asp} + \Sigma PE_{sp} + \Sigma PE_{unsp} - \Sigma SE_{sp}$$

Where:

ΣE_{asp} = Sum of CO_2e emissions from each specified facility/unit in the asset-controlling supplier's fleet, consistent with section 95111(b)(2) (MT of CO_2e).

ΣEG_{asp} = Sum of net generation for each specified facility/unit in the asset-controlling supplier's fleet for the data year as reported to ARB under this article (MWh).

PE_{sp} = Amount of electricity purchased wholesale and taken from specified sources by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

PE_{unsp} = Amount of electricity purchased wholesale from unspecified sources by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

SE_{sp} = Amount of wholesale electricity sold from a specified source by the asset-controlling supplier for the data year as reported to ARB under this article (MWh).

EF_{sp} = CO_2e emission factor as defined for each specified facility or unit calculated consistent with section 95111(b)(2) (MT CO_2e/MWh).

EF_{unsp} = CO_2e default emission factor for unspecified sources calculated consistent with section 95111(b)(1) (MT CO_2e/MWh).

Multi-jurisdictional retail providers include emissions and megawatt-hours in the terms above from facilities or units that contribute to a common system power pool. Multi-jurisdictional retail providers do not include emissions or megawatt-hours in the terms above from facilities or units allocated to serve retail loads in designated states pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service.

(4) *Calculating GHG Emissions of Imported Electricity from Multi-jurisdictional Retail Providers*. Multi-jurisdictional retail providers must calculate emissions using the following equation:

$$CO_2e = \left(MWh_R - MWh_{WSP-CA} - EG_{CA}\right) \times TL \times EF_{MJRP} + MWh_{WSP-notCA} \times TL \times EF_{MJRP} - CO_2e_{linked}$$

Where:

CO_2e = Annual CO_2e mass emissions of imported electricity (metric tons).

MWh_R = Total electricity procured by multi-jurisdictional retail provider to serve its retail customers in California, reported as retail sales for California service territory, MWh.

MWh_{WSP-CA} = Wholesale electricity procured in California by multi-jurisdictional retail provider to serve its retail customers in California, as determined by the first point of receipt on a NERC E-tag and pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service, MWh.

$MWh_{WSP\text{-}not\ CA}$ = Wholesale electricity imported into California by multi-jurisdictional retail provider with a final point of delivery in California and not used to serve its California retail customers, MWh.

EF_{MJRP} = Multi-jurisdictional retail provider system emission factor calculated by ARB pursuant to subsection 95111(b)(3) and consistent with a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service.

EG_{CA} = net generation measured at the busbar of facilities and units located in California that are allocated to serve its retail customers in California pursuant to a cost allocation methodology approved by the California Public Utilities Commission (CPUC) and the utility regulatory commission of at least one additional state in which the multi-jurisdictional retail provider provides retail electric service, MWh.

TL = Transmission loss correction factor.

TL = 1.02 when transmission losses are not made up in other electricity deliveries reported or from California sources.

TL = 1.0 when transmission losses are made up in other electricity deliveries reported or from California sources.

(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 section 95111(a)-(b).

(1) Retail providers that serve California load must report California retail sales.
(2) Retail providers may elect to report the subset of retail sales attributed to the electrification of shipping ports, truck stops, and motor vehicles if metering is available to separately track these sales from other retail sales.
(3) Retail providers that serve California load must claim as specified electricity all electricity imported from facilities or units in which they have an ownership share or written contract to procure electricity.
(4) For facilities or units that are fully or partially owned by a retail provider that have GHG emissions greater than the default emission factor for unspecified imported electricity based on the most recent GHG emissions data report submitted to ARB or U.S. EPA, the retail provider must include:

(A) The facility name, ARB facility identification number and generating unit identification number as applicable, percent ownership share at the facility level, ownership share at the generating unit level as applicable, both net and gross nameplate capacity, and both net and gross power generated in the report year;
(B) The quantity of electricity sold by the retail provider or on behalf of the retail provider from the facility or unit having a final point of delivery outside California, as measured at the busbar.

(5) Retail providers that report as electricity importers also must separately report electricity imported from specified and unspecified sources by other electric power entities to serve their load, designating the electricity importer.

(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).

(1) A report of the electricity transactions and GHG emissions associated with the common power system or contiguous service territory that includes consumers

in California. This includes the requirements in this section as applicable for each generating facility or unit in the multi-jurisdictional retail provider's fleet;

(2) The multi-jurisdictional retail provider must 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) Total retail sales (MWh) by the multi-jurisdictional retail provider in the contiguous service territory or power system that includes consumers in California;

(4) Retail sales (MWh) to California customers served in California's portion of the service territory;

(5) GHG emissions associated with the imported electricity, including both California retail sales and wholesale power imported into California from the retail provider's system, according to the specifications in this section;

(6) Multi-jurisdictional retail providers that serve California load must claim as specified power all power purchased or taken from facilities or units in which they have operational control or an ownership share or written contract;

(7) Multi-jurisdictional retail providers must provide the supplier-specific ARB identification number to electric power entities who purchase electricity from the supplier's system.

(e) *GHG Emissions Data Report:* Additional Requirements for WAPA and DWR.

(1) In reporting its GHG emissions to ARB, the California Department of Water Resources shall include all applicable information identified in this article for retail providers, including the amount of electricity used for pump loads, to operate the State Water Project.

(2) In reporting its GHG emissions to ARB, the Western Area Power Agency shall include all applicable information identified in this article for retail providers, including the amount of electricity used for pump loads, to operate the Central Valley Project.

(f) *GHG Emissions Data Report:* Additional Requirements for Asset-Controlling Suppliers. Bonneville Power Administration may 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 asset-controlling supplier that chooses this option must:

(1) Meet the requirements in this section 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.

(g) *Requirements for Claims of Specified Sources of Imported Electricity and Associated Emissions.* Electricity importers must register specified sources and report associated GHG emissions as follows:

(1) *Registration of Specified Sources and Suppliers.* Each electricity importer claiming specified sources or suppliers of electricity must register its specified sources and suppliers of electricity with ARB prior to January 1 of each reporting year. For purposes of registration under this paragraph, specified sources are facilities and units. Specified suppliers are asset-controlling suppliers and multi-jurisdictional retail providers. The electricity importer must include the following information when it registers its specified sources and suppliers:

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

(B) For sources with a previously assigned ARB identification number, the ARB facility or unit identification number or supplier number published on ARB's mandatory reporting program website. For newly specified sources, ARB will assign a unique identification number.

(C) The facility and unit identification numbers as used for reporting to the Energy Information Administration, U.S. EPA Acid Rain Program, U.S. EPA pursuant to 40 CFR Part 98, and the California Energy Commission Eligible Renewable Resource identification number, as applicable.

(D) The physical address of each facility, including jurisdiction.

(E) The percent ownership share and whether the facility or unit is under the electricity importer's operational control.

(F) Total facility or unit gross and net nameplate capacity.

(G) Designate whether the facility emitted less than 25,000 metric tons of CO_2e as reported in the most recent GHG report to the ARB or to the U.S. EPA.

(H) Designate whether the facility or unit is a newly specified source, a continuing specified source, or was a specified source in the previous report year that will not be specified in the current report year.

(I) Provide the primary technology or fuel type as listed below:

1. Variable renewable resources by type, defined for purposes of this article as pure solar, pure wind, and run-of-river hydroelectricity;
2. Hybrid facilities such as solar thermal;
3. Hydroelectric facilities ≤ 30 MW, not run-of-river;
4. Hydroelectric > 30 MW;

5. Geothermal binary cycle plant or closed loop system;
6. Geothermal steam plant or open loop system;
7. Biomass-derived sources by primary fuel type;
8. Nuclear facilities;
9. Cogeneration by primary fuel type;
10. Fossil sources by primary fuel type;
11. Co-fired fuels;
12. Municipal solid waste combustion;
13. Other.

(2) *Emission Factors.* The emission factor published on the ARB Mandatory Reporting website, calculated by ARB according to the methods in section 95111(b), must be used when reporting GHG emissions for a specified source of electricity.

(3) *Owned Sources.* Electricity importers must report as specified sources of electricity the imported electricity from generating facilities or units located outside the state of California in which they have an ownership share, or written contract for a specified percentage of a facility's or unit's generation in the report year.

(4) *Delivery Tracking Conditions Required for Specified Electricity Imports.* Electricity importers may claim a specified source when the electricity delivery meets one of the following sets of conditions:

(A) The electricity importer has an ownership share in the facility or unit or a written contract for a specified percentage of the facility's or unit's generation in the report year;

(B) The electricity importer has a written contract to receive electricity generated by the facility or unit.

(5) *High GHG-Emitting Facilities or Units.* For facilities or units that are operated by a retail provider or fully or partially owned by a retail provider, excluding multi-jurisdictional retail providers, and that have emissions greater than the default emission factor for unspecified electricity based on the most recent GHG emissions data report submitted to ARB or to U.S.EPA, the retail provider must report the following information.

(A) When the product of net generation (MWh) and ownership share is greater than imported electricity (MWh), emissions transferred outside California must be reported as

$$CO_2e = (EG_{sp} * OS - I_{sp}) * EF_{sp.}$$

Where:

EG_{sp} = facility or unit net generation, MWh.

OS = fraction ownership share.

I_{sp} = imported electricity, MWh.

$EF_{sp.}$ = facility or unit-specific emission factor, MT of CO_2e/MWh.

(B) List the replacement generation sources, locations, and whether they are new units when I_{sp}< 90% of EG_{sp}*OS and for a facility specified in the previous report year that has no imported electricity in the report year.

(6) *Low GHG-Emitting Existing, Fully Committed Resources: Nuclear and Large Hydroelectric Resources.* An emission factor of zero MT of CO_2e/MWh may only be used when electricity imported into California from a specified hydroelectric generating facility with nameplate capacity greater than 30 MW or a nuclear facility that was operational prior to January 1, 2010 meets one of the following conditions:

(A) Electricity purchased with a written contract in effect prior to January 1, 2010 that remains in effect or has been renegotiated for the same facility for the same share or quantity of net generation within one year of contract expiration;
(B) Electricity purchased that does not meet the first requirement that is associated with an increase in the facility's generating capacity due to increased efficiencies or other capacity increasing actions;
(C) Electricity purchased from hydroelectric generating facilities during a "spill or sell" situation where power not purchased is lost;
(D) Electricity purchased that does not meet the first requirement due to federal power redistribution policies for federally owned resources and not related to price bidding.

If none of the conditions in (A) through (D) above are met, apply the default emission factor for unspecified electricity pursuant to section 95111(b).

(7) *Substitute electricity.* Report substitute electricity received from specified and unspecified sources pursuant to the requirements of this section. Substitute electricity is provided under contract with specified facilities, not classified as variable renewable resources, to meet delivery requirements when the specified facility or unit is not operating.

NOTE: Authority cited: Sections 39600, 39601, 39607, 39607.4, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, 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 comply with Subparts C and D of 40 CFR Part 98 (§§98.30 to 98.48), as applicable, in reporting emissions from electricity generating and cogeneration units to ARB, except as otherwise provided in this section.

(a) *Basic Information for EGUs*. Notwithstanding any limitations in 40 CFR Parts 75 or 98, the operator of an electricity generating unit is required to include in the emissions data report the information listed in this paragraph. For aggregation of units that meet the applicable criteria in 40 CFR §98.36(c)(1)-(3), the operator may elect to report the following information for a group of aggregated units, in lieu of separately reporting for each single unit.

(1) Nameplate generating capacity in megawatts (MW);
(2) Net and gross power generated, in megawatt hours (MWh);
(3) Fuel consumption by fuel type, reporting 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;
(4) If not already required to be reported under 40 CFR §98.36(b)(6), annual CO_2, CH_4, and N_2O emissions from the unit, expressed in metric tons of each gas;
(5) If used to calculate CO_2 emissions and not already required to be reported under 40 CFR §98.36(b)(6), weighted average carbon content and high heat value by fuel type, determined using the same procedures as specified for HHV in 40 CFR §98.32(a)(2)(ii).
(6) For facilities whose primary sector is not electricity generation, report the following electricity generation information at the facility level, if known:
    (A) Electricity sold to the grid (MWh),
    (B) Electricity sold or provided directly to end-users (MWh), end-user's NAICS code and ARB ID (if an ARB ID has been assigned),
    (C) Electricity consumed on-site (MWh).

(b) *Basic Information for Cogeneration Units.* In addition to the information required by paragraph (a) of this section, the operator of a cogeneration unit must:

(1) Indicate whether the unit is topping or bottoming cycle, and the prime mover technology;
(2) Provide useful thermal output (mmBtu);
(3) Where steam or heat is acquired from another facility for the generation of electricity, report the provider, the provider's ARB ID, and the amount of acquired steam or heat (mmBtu);
(4) Where supplemental firing has been applied to support electricity generation or industrial output, report fuel consumption by fuel type using the units in paragraph (a)(3) of this section and indicate the purpose of the supplemental firing.

(c) *CO_2 from Fossil Fuel Combustion*. When calculating CO_2 emissions from fuel combustion, the operator who is subject to Subpart C or D of 40 CFR Part 98 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) *Monitoring, Data and Records*. For each emissions calculation method chosen under section 95112(c), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95112, 95115, and 95129 of this article.

(e) *Biomass Emissions for Units Reporting Under 40 CFR Part 75.* Operators of electricity generating and cogeneration units subject to 40 CFR Part 75 and the data reporting requirements in 40 CFR §98.36(d) that combust both fossil and biomass-derived fuels must separately report CO_2 emissions from combustion of fossil fuels and CO_2 emissions from the combustion of biomass-derived fuels. The biogenic portion of CO_2 emissions must be calculated according to the methodology specified in 40 CFR §98.33(e).

(f) *CO_2 and CH_4 Emissions from Geothermal Facilities.* Operators of geothermal generating facilities must calculate annual emissions of CO_2 and CH_4 from geothermal energy sources using source specific emission factors derived from a measurement plan approved by the ARB. The operator must submit to the Executive Officer a measurement plan at least 45 days prior to the first test date. The measurement plan must include testing at least annually, and more frequently as needed. Upon approval of the measurement plan by the Executive Officer, the test procedures in that plan must be performed as specified in the plan. The Executive Officer and the local air pollution control officer must be notified at least 20 days in advance of subsequent tests.

(g) *Hydrogen Fuel Cells.* Operators of stationary hydrogen fuel cell units that produce hydrogen on-site must report information on the feedstocks used in hydrogen production. The operator must include the following information in the annual GHG emissions data report:

(1) Nameplate generating capacity in megawatts (MW);
(2) Net and gross power generated, in megawatt hours (MWh);
(3) Fuel or feedstock consumption by fuel/feedstock type, reporting 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;
(4) The provider of each fuel or feedstock, and the user's customer account number;
(5) Cogeneration information in section 95112(b), if applicable.

(h) *Missing Data Substitution Procedures.* To substitute for missing data for emissions reported under sections 95112 or 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article. Facilities reporting under 40 CFR Part 75 must substitute for missing data under the requirements of that part, as specified in 40 CFR §98.45.

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

§ 95113. Petroleum Refineries.

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 comply with Subpart Y of 40 CFR Part 98 (40 CFR §§98.250 to 98.258) in reporting annual emissions from petroleum refineries to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion under subpart C as specified at 40 CFR §98.252(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. CO_2 emissions from refinery fuel gas combustion must be calculated using a Tier 3 or Tier 4 methodology of subpart C, as specified in 40 CFR §98.252(a).

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95113(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95113(l), 95115, and 95129 of this article.

(c) *Refinery Fuel Gas Sampling.* As required by 40 CFR §98.34(b)(3)(ii)(E), in cases where equipment necessary to perform daily sampling and analysis of carbon content and molecular weight for refinery fuel gas is not in place, such equipment must be installed and procedures established to implement daily sampling and analysis no later than January 1, 2013.

(d) *Calculating CO_2 from Flares.* For periods of normal flare operation, the operator must use Equation Y-1 or Equation Y-2 as specified in 40 CFR §98.253(b)(ii)(A) or 98.253(b)(ii)(B). For periods of startup, shutdown, and malfunction (SSM) during which the operator was unable to measure the parameters required by Equations Y-1 and Y-2, the operator must determine the quantity of gas discharged to the flare separately for each SSM, and calculate the CO_2 emissions as specified in the equation shown below. For SSM periods the operator must use engineering calculations and process knowledge to estimate the carbon content of flared gas as required by §98.253(b)(iii)(A). The terms of the equation below are defined as they are for Equation Y-3 in 40 CFR §98.253(b)(iii)(C).

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[44/12 \times (Flare_{SSM})_p \right] \times MW_p / MVC \times CC_p \right)$$

(e) *Calculating CO_2 from FCCUs and Fluid Coking.* The requirements of 40 CFR §98.253(c)(2) apply under this article regardless of the rated capacity of a fluid catalytic cracking unit or a fluid coking unit. The operator may not use Equation Y-8 or the option provided under 40 CFR §98.253(c)(3) for units with rated capacities of 10,000 barrels per stream day or less.

(f) *Calculating CH_4 from Delayed Coking Units.* When calculating CH_4 emissions from the depressurization of the coking unit vessel as required by 40 CFR §98.253(i), the operator must conduct the sampling and engineering analysis necessary to apply the two terms below, from Equation Y-18, modified as follows:

f_{void} = Volumetric void fraction of coking vessel prior to steaming based on engineering calculations (cf gas/cf of vessel).

MF_{CH4} = Average mole fraction of methane in coking vessel gas based on the analysis of at least two samples per year, collected at least four months apart (kg-mole CH_4/kg-mole gas, wet basis).

(g) *Uncontrolled Blowdown Systems.* When calculating CH_4 emissions for uncontrolled blowdown systems as required by 40 CFR §98.253(k), the operator must use the methods for process vents in 40 CFR §98.253(j).

(h) *Data Reporting Requirements for Flares.* When the operator has calculated flare emissions for SSM periods using the modified equation specified in section 95113(d), the operator reporting data under the requirements of 40 CFR §98.256(e)(8) must report only the total number of SSM events, the volume of gas flared, and the average molecular weight and carbon content of the flare gas for each SSM event, using the units specified.

(i) *Data Reporting Requirements for FCCUs and Coking Units.* When the operator has calculated CO_2 from fluid catalytic cracking units or fluid coking units consistent with section 95113(e), the operator shall not report the data required by 40 CFR §98.256(f)(9).

(j) *Data Reporting Requirements for Uncontrolled Blowdown Systems.* When the operator has calculated CH_4 from uncontrolled blowdown systems consistent with section 95113(g), the operator must report the information required for process vents in 40 CFR §98.256(l), as applicable, in lieu of the information required by 40 CFR §98.256(m)(2).

(k) *Records that must be retained.* In addition to the requirements of 40 CFR §98.257, for each process vent for which the concentration of CO_2, N_2O and CH_4 are determined to be below the thresholds in 40 CFR §98.253(j), the operator must maintain records of the method used to determine the CO_2, N_2O, and CH_4 concentrations, and all supporting documentation necessary to demonstrate that the thresholds in 40 CFR §98.253(j) are not exceeded during the data year pursuant to the record keeping requirements of section 95105.

(l) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.255 when substituting for missing data, except as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For all other data required for emissions calculations in this section, the operator must follow the requirements of paragraphs (A)-(B) below.

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(m) *Additional Data Reporting Requirements for Benchmarking Purposes*. The operator must report production quantities for the data year of each petroleum product listed in Table C-1 of 40 CFR Part 98, and each additional transportation fuel product listed in Table MM-1 of 40 CFR Part 98 (standard cubic feet for gaseous products, gallons for liquid products, short tons for solid products).

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

§ 95114. Hydrogen Plants.

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 comply with Subpart P of 40 CFR Part 98 (40 CFR §§98.160 to 98.168) in reporting annual emissions from hydrogen production to ARB, except as otherwise provided in this section.

(a) *Definition of Source Category.* This source category includes merchant hydrogen production facilities located within another facility if they are not owned by, or under the direct control of, the other facility's owner or operator.

(b) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion under subpart C as specified at 40 CFR §98.162(b)-(c), 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.

(c) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95114(b), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95114(h), 95115, and 95129 of this article.

(d) *CO_2 Process Emissions.* When calculating CO_2 under the fuel and feedstock material balance approach specified at 40 CFR §98.163(b), the operator must apply the weighted average carbon content values obtained (the term CC_n in Equations P-1 through P-3) according to the frequencies specified in section 95114(e).

(e) *Sampling Frequencies.* When monitoring GHG emissions without a CEMS as specified at 40 CFR §98.164(b)(2), and reporting data as specified at §98.166, the operator must determine the carbon content and molecular weight values for fuels and feedstocks according to the frequencies specified below.

(1) When reporting CO_2 emissions for gaseous fuel and feedstock as specified in 40 CFR §98.163(b)(1), the operator must use a weighted average carbon content from the results of one or more analyses for month n for natural gas, or from daily analysis for gaseous fuels and feedstocks other than natural gas;
(2) When reporting CO_2 emissions for liquid fuel and feedstock as specified in 40 CFR §98.163(b)(2), the operator must use weighted average carbon content from the results of daily sampling for month n. Daily liquid samples may be combined to generate a monthly composite sample for carbon analysis;
(3) When reporting CO_2 emissions for solid fuel and feedstock as specified in 40 CFR §98.163(b)(3), the operator must use weighted average carbon content from the results of daily sampling for month n. Daily solid samples may be combined to generate a monthly composite sample for carbon analysis.

(f) *Weighted Average Sampling.* Where this section requires sampling of a parameter on a more frequent basis than 40 CFR Part 98, the operator or supplier must comply with the following:

(1) The samples must be spaced apart as evenly as possible over time, taking into account the operating schedule of the relevant unit or facility.
(2) The operator or supplier must calculate and report a weighted average of the values derived from the samples by using the following formula:

$$V_E = \frac{\sum_{j=1}^{n}(V_j \times M_j)}{\sum_{j=1}^{n} M_j}$$

Where:

V_E = The value of the parameter to be reported under 40 C.F.R. Part 98 for period E.

j = Each period during period E for which a sample is required by this article.

n = The number of periods j in period E.

V_j = The value of the sample for period j.

M_j = The mass of the sampled material processed or otherwise used by the relevant unit or facility in period j.

(3) The operator or supplier must keep records of the date and result for each sample or composite sample and mass measurement used in the equation above and of the calculation of each weighted average included in the emissions data report, pursuant to the record keeping requirements of section 95105.

(g) *Data Reporting Requirements.* When reporting data as specified at §98.166, the operator must also report the amount of carbon in unconverted feedstock for which GHG emissions are calculated and reported by the facility using other calculation methods provided in this regulation. For example, carbon in waste diverted to a fuel system or flare, where the CO_2 and CH_4 emissions are calculated and reported using other methods provided in this regulation, should be separately specified (metric tons of CO_2e/year). The operator must also report the amount of hydrogen produced and sold as a transportation fuel, if known.

(h) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.165 when substituting for missing data, except as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For all other data required for emissions calculations in this section, the operator must follow the requirements of paragraphs (A)-(C) below.

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

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

§ 95115. Stationary Fuel Combustion Sources.

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 comply with Subpart C of 40 CFR Part 98 (§§98.30 to 98.38) in reporting annual stationary fuel combustion emissions to ARB, except as otherwise provided in this section.

(a) *CO_2 from Steam Producing Units.* The operator of a steam producing unit combusting municipal solid waste or solid biomass fuels may use Equation C-2c of 40 CFR §98.33(a)(2)(B)(iii). Operators of units combusting fossil-based solid fuels must select applicable Tier 3 or Tier 4 methods.

(b) *CEMS CO_2 Monitoring.* Notwithstanding the allowance of oxygen concentration monitors in 40 CFR 98.33(a)(4)(iv), an operator installing a continuous emissions monitoring system that includes a stack gas volumetric flow rate monitor after January 1, 2012 must install and use a CO_2 monitor to report CO_2 emissions. An operator without a CO_2 monitor who uses a CEMS and O_2 concentrations to calculate and report a unit's CO_2 emissions, and who conducts a Relative Accuracy Test Audit (RATA) for the unit, must at least annually include in the RATA the direct monitoring of CO_2 concentration and flow, and the calculation of CO_2 mass per hour. The operator must retain these results pursuant to the recordkeeping requirements of section 95105 and make them available to ARB upon request. The requirements of this paragraph do not apply to facilities for which pipeline natural gas is the only fuel consumed.

(c) *Choice of Tier for Calculating CO_2 Emissions.* Notwithstanding the provisions of 40 CFR §98.33(b), the operator's selection of a method for calculation of CO_2 emissions from combustion sources is subject to the following limitations by fuel type and unit size. The operator is permitted to select a higher tier than that required for the fuel type or unit size as specified below.

(1) The operator may select the Tier 1 or Tier 2 calculation method specified in 40 CFR §98.33(a) for any fuel listed in Table 1 of this section that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less, subject to the limitation at 40 CFR §98.33(b)(1)(iv), or for biomass-derived fuels not subject to a compliance obligation under the Cap-and-Trade Regulation, when listed in Table C-1 of 40 CFR Part 98.

(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. Equation C-2c may be selected for the units specified in paragraph (a) of this section.

(3) The operator may select any calculation method specified in 40 CFR §98.33(a) when calculating emissions that are shown to be *de minimis* under section 95103(i)of this article, or for a fuel providing less than 10 percent of the annual heat input to a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less, unless not permitted under 40 CFR §98.33(b).

(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, subject to the limitations of 40 CFR §98.33(b)(4)-(5) requiring use of the Tier 4 method.

(d) *Source Test Option for N_2O and CH_4.* In lieu of other methods specified in this article, a facility operator may conduct site-specific source testing to derive emission factors and determine annual emissions of N_2O or CH_4 from any combustion source. Alternatively, the operator may use the results of an applicable test method specified in title 17, California Code of Regulations, section 95471. For source testing:

(1) The facility operator must submit to the Executive Officer a test plan at least 45 days prior to the first test date. The test plan must provide for testing at least annually, and more frequently as needed to account for seasonal variations in fuels or processes.

(2) The plan must specify conduct of performance and stack tests consistent with the requirements of approved ARB or U.S. EPA test methods. Process rates during the test must be determined in a manner that is consistent with the procedures used for GHG report accounting purposes.

(3) Upon approval of the test plan by the Executive Officer, the test procedures in that plan must be repeated as specified in the plan. The Executive Officer and the local air pollution control officer must be notified at least ten days in advance of subsequent tests.

(e) *Procedures for Biomass CO_2 Determination.* When combusting MSW or any other fuel for which the biomass fraction is not known, the operator must follow the procedures specified in 40 CFR §98.33(e)(3) to specify a biomass fraction.

(f) *Fuel Sampling Frequencies.* The operator who collects and analyzes fuel samples to conduct the monitoring analyses required under 40 CFR §98.34 must sample at the frequencies specified in that section, except in the following cases.

(1) Natural gas that is outside the range of pipeline quality as defined in section 95102 must be sampled and analyzed at least monthly by the reporting entity or the fuel supplier.

(2) Under 40 CFR §98.34(b)(3)(ii)(E), in cases where equipment necessary to perform daily sampling and analysis of carbon content and molecular weight

for refinery fuel gas is not in place, such equipment must be installed and procedures established to implement daily sampling and analysis no later than January 1, 2013.

(g) *Electricity Generating and Cogeneration Units.* The operator of a facility that includes electricity generating and cogeneration units meeting the applicability criteria of section 95101 must meet the requirements specified in section 95112 of this article.

(h) *Natural Gas Provider.* The operator must report the provider(s) of natural gas to the facility, and the operator's customer account number(s).

(i) *Procedures for Missing Data.* To substitute for missing data for emissions reported under section 95115 of this article, the operator must follow the requirements of section 95129.

(j) *Additional Data to Support Benchmarking.* Operators of the following types of facilities must also report the production quantities indicated below.

(1) The operator of a facility engaged in the production and manufacture of hot rolled sheet steel, galvanized sheet steel, or both, must report the quantity of hot rolled sheet steel and galvanized sheet steel produced in the data year (short tons).

(2) The operator of a soda ash manufacturing facility must report the quantity of soda ash produced in the data year (short tons).

(3) The operator of a gypsum manufacturing facility must report quantities produced of each of the following products (short tons): dry gypsum; plaster; gypsum blocks, plasterboards and coving; and glass-fiber reinforced gypsum (GRG) plasterboards.

Table 1: Petroleum Fuels For Which Tier 1 or Tier 2 Calculation Methodologies May Be Used Under Section 95115(c)(1)

Fuel Type	***Default High Heat Value***	***Default CO_2 Emission Factor***
	mmBtu/gallon	*kg CO_2 /mmBtu*
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)[1]	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15

[1] Commercially sold as "propane," including grades such as HD5.

Table 1: Petroleum Fuels For Which Tier 1 or Tier 2 Calculation Methodologies May Be Used Under Section 95115(c)(1)

Fuel Type	***Default High Heat Value***	***Default CO_2 Emission Factor***
Butylene	0.103	67.73
Natural Gasoline	0.110	66.83
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22

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

§ 95116. Glass Production.

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 comply with Subpart N of 40 CFR Part 98 (§§98.140 to 98.148) in reporting annual stationary combustion and process emissions from glass production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, 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.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95116(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95116(c), and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.145 when estimating missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For each missing value of the monthly amounts of carbonate-based raw materials charged to any continuous glass melting furnace, the operator must apply a substitute value according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.145(a).
(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum tons per day raw material capacity of the continuous glass melting furnace.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Data to Support Benchmarking.* In addition to the information required by 40 CFR §98.146, the operator must report the additional parameters provided in paragraphs (1)-(2) below whether or not a CEMS is used to measure CO_2 emissions.

(1) Annual quantity of packed or sellable glass produced (short tons).
(2) Annual quantity of fiberglass produced (short tons).

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

§ 95117. Lime Manufacturing.

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 comply with Subpart S of 40 CFR Part 98 (§§98.190 to 98.198) in reporting annual stationary combustion and process emissions from lime manufacturing to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fuel combustion, 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.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95117(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95117(c), and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.195 when substituting for missing data, except as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If CaO and MgO content data required by 40 CFR §98.193(b)(2) are missing and a new analysis cannot be undertaken, the operator must apply substitute values according to the procedures in paragraphs (A)-(C) below.

    (A) If the data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using the best available estimate of the parameter, based on all available process data.

    (B) If the data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

    (C) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(3) For each missing value of the quantity of lime produced (by lime type) and quantity of lime byproduct/waste produced and sold, the operator must apply a substitute value according to the procedures in paragraphs (A)-(B) below.

    (A) If the data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.195(a).

    (B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum capacity of the system.

(4) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

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

§ 95118. Nitric Acid Production.

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 comply with Subpart V of 40 CFR Part 98 (§§98.220 to 98.228) in reporting annual stationary combustion and process emissions from nitric acid production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion at a stationary combustion unit under 40 CFR §98.222(b), the operator must use a method in 40 CFR §98.33(a)(2) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95118(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95118(d), and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.225 when substituting for missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For each missing value of nitric acid production, the operator must substitute the missing data values according to the procedures in paragraphs (A)-(B) below.

(A) If the analytical data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.225(a) and the number of days per month.

(B) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum capacity of the system and the number of days per month.

(3) The operator must document and keep records of the procedures used for estimating missing data pursuant to the recordkeeping requirements of section 95105.

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

§ 95119. Pulp and Paper Manufacturing

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 comply with Subpart AA of 40 CFR Part 98 (40 CFR §§98.270 to 98.278) in reporting annual stationary combustion and process emissions from pulp and paper manufacturing to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion in a chemical recovery furnace at a kraft or soda facility under 40 CFR §98.273(a)(1), a chemical recovery unit at a sulfite or stand-alone semichemical facility under 40 CFR §98.273(b)(1), a pulp mill lime kiln at a kraft or soda facility under 40 CFR §98.273(c)(1), or other stationary fuel combustion sources, 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.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95119(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95119(c), and 95129 of this article.

(c) *Procedures for Missing Data.* The operator must comply with 40 CFR §98.275 when substituting for missing data, except as otherwise provided in paragraphs (1)-(3) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) For each missing value for the use of makeup chemicals (carbonates), the operator must apply a substitute value according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute each missing value according to 40 CFR §98.275(c).

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum metric tons per day capacity of the system.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Data to Support Benchmarking.* In addition to the information required by 40 CFR §§98.276, the operator must report the annual production (short tons) of each of the following: pulp purchased or manufactured, secondary fiber from recycled paper purchased or manufactured, paper products manufactured from purchased pulp by product type, paper converted into paperboard products by product type, and the quantity of coated or laminated products by paper product type.

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

§ 95120. Iron and Steel Production

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 comply with Subpart Q of 40 CFR Part 98 (40 CFR §§98.170 to 98.188) in reporting annual stationary combustion and process emissions from iron and steel production to ARB, except as otherwise provided in this section.

(a) *CO_2 from Fossil Fuel Combustion.* When calculating CO_2 emissions from fossil fuel combustion at a stationary combustion unit under §98.172(a), the operator must use a method in §98.33(a)(1) to §98.33(a)(4) as specified by fuel type in section 95115 of this article.

(b) *Monitoring, Data and Records.* For each emissions calculation method chosen under section 95120(a), the operator must meet the applicable requirements for monitoring, missing data procedures, data reporting, and records retention that are specified in 40 CFR §98.34 to §98.37, except as modified in sections 95115, 95120(c), and 95129 of this article.

(c) *Missing Data Substitution Procedures.* The operator must comply with 40 CFR §98.175 when substituting for missing data, except as otherwise provided in paragraphs (1)-(2) below.

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If monthly mass or volume of carbon-containing inputs and outputs are missing when using the carbon mass balance procedure in 40 CFR §98.173(b)(1), the operator must apply substitute values according to the procedures in paragraphs (A)-(B) below.

(A) If the data capture rate is at least 80 percent for the data year, the operator must substitute for each missing value based on the best available estimate based on information used for accounting purposes (such as purchase records).

(B) If the data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the maximum throughput capacity of the system.

(3) The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

(d) *Additional Data to Support Benchmarking.* 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 metric tons and a description of the product(s).

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

§ 95121. Suppliers of Transportation Fuels.

Any position holder, enterer, refiner, or biomass-derived fuel producer 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 annual emissions to ARB, except as otherwise provided in this section.

(a) *GHGs to Report.*

(1) In addition to the CO_2 emissions specified under 40 CFR §98.392, all refiners that produce liquefied petroleum gas must 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 (ex refinery gate), except for products for which a final destination outside California can be demonstrated.

(2) Refiners, position holders, and enterers of fossil fuels and biomass-derived fuels and producers of biomass-derived 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 petroleum product or biomass-derived fuel listed in Tables MM-1 or MM-2 of 40 CFR Part 98, except that distillate fuel oil is limited to diesel fuel as defined in this regulation and except for products for which a final destination outside California can be demonstrated. No fuel shall be reported as finished fuel. Fuels must be reported as the blendstock or diesel fuel plus any other components.

(b) *Calculating GHG emissions.*

(1) Refiners, position holders at California terminals, enterers who bring fuel into California outside the bulk transfer/terminal system, and biomass-derived fuel producers 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 product removed from the rack (for refiners and position holders), imported (by enterers), sold to unlicensed entities as specified in section 95121(d)(3) (by refiners), or produced (by biomass-derived fuel producers). For fuels that are mixtures of multiple components, emissions must be reported for each

individual component separately, and not as finished motor gasoline, biofuel blends, or other similar finished fuel. Emission factors must be taken from column C of 40 CFR Part 98 Table MM-1 as specified in Calculation Method 1 of 40 CFR §98.393(f)(1).

(2) Refiners that produce liquefied petroleum gas 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 product supplied. For calculating the emissions from liquefied petroleum gas, the emissions from the individual components must be summed. Emission factors must be taken from column C of 40 CFR Part 98 Table MM-1 as specified in Calculation Method 1 of 40 CFR §98.393(f)(1).

(3) Refiners, position holders at California terminals, enterers outside of the bulk transfer/terminal system, and biomass-derived fuel producers 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).

(4) All fuel suppliers in this section must estimate CO_2e emissions using the following equation:

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.

GHG_i = Mass emissions of CO_2, CH_4, N_2O from fuels combusted or oxidized.

GWP_i = Global warming potential for each greenhouse gas from Table A-1 of 40 CFR Part 98.

n = Number of greenhouse gases emitted.

(c) *Monitoring and QA/QC Requirements.* For the emissions calculation method chosen under section 95121(b), the operator must meet all the monitoring and QA/QC requirements as specified in 40 CFR §98.394, and the requirements of 40 CFR §98.3(i) as further specified in section 95103 of this article and below.

(1) Position holders are exempt from 40 CFR §98.3(i) calibration requirements except when the fuel supplier and fuel receiver have common ownership or are owned by subsidiaries or affiliates of the same company. In such cases the 40 CFR §98.3(i) calibration requirements apply, unless:

(A) The fuel supplier does not operate the fuel billing meter;

(B) The fuel billing meter is also used by companies that do not share common ownership with the fuel supplier; or

(C) The fuel billing meter is sealed with a valid seal from the county sealer of weights and measures and the operator has no reason to suspect inaccuracies.

(2) As required by 40 CFR §98.394(a)(1)(iii), for products that are liquid at 60 degrees Fahrenheit and one standard atmosphere, the volume reported must

be temperature- and pressure-adjusted to these conditions. For liquefied petroleum gas the volume reported must be temperature-adjusted to 60 degrees Fahrenheit.

(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, and as corrected to reflect the individual components of the product, for each petroleum product or biomass-derived fuel listed in 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 products for which a final destination outside California can be demonstrated.

(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 corrected to reflect the individual components of the product, for each petroleum product or biomass-derived fuel listed in Tables MM-1 and MM-2 of 40 CFR Part 98, except distillate fuel oil is limited to diesel fuel and except for products for which a final destination outside California can be demonstrated.

(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 corrected to reflect the individual components of the product, for each petroleum product or biomass-derived fuel listed in Tables MM-1 and MM-2 of 40 CFR Part 98, except Distillate Fuel Oil is limited to diesel fuel and except for products for which a final destination outside California can be demonstrated.

(4) Enterers must report the annual quantity in barrels, as reported on the bill of lading or other shipping documents, corrected to reflect the individual components of the product, for each petroleum product or biomass-derived fuel listed in 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 products for which a final destination outside California can be demonstrated.

(5) Producers of biomass-derived fuels in California must report the annual quantity in barrels, as measured at a custody transfer meter or listed on a bill of lading, corrected to reflect the individual components of the product, for each fuel listed in Tables MM-1 and MM-2 of 40 CFR Part 98 that is delivered in California, except for products for which a final destination outside California can be demonstrated. This requirement does not apply to the annual reporting of the total volume of biodiesel, renewable diesel, and denatured fuel ethanol produced or imported, if this information has been provided under the requirements of title 17, California Code of Regulations, sections 95480-95490 (Low Carbon Fuel Standard).

(6) Biomass-derived fuel producers in California that blend biomass-derived fuel with fossil fuels outside the bulk transfer/terminal system must indicate the

supplier or source of the fossil-based fuels when reporting component volumes.

(7) In addition to the information required in 40 CFR §98.396 petroleum refineries 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 products for which a final destination outside California can be demonstrated.

(8) All fuel suppliers identified in this section must also report CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O and CO_2e emissions in metric tons that would result from the complete combustion or oxidation of each petroleum product, liquefied petroleum gas, or biomass-derived fuel reported in this section, calculated according to section 95121(b).

(9) Enterers and biomass-derived fuel producers who deliver fuel to position holders at terminals or refiners must report the name of the recipient and the volumes delivered according to the bill of lading or other sales document.

(e) *Procedures for Missing Data.* For quantities of fuels that are purchased, sold, or transferred in any manner, fuel suppliers must follow the missing data procedures specified in 40 CFR §98.395. The supplier must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105. If any combination of data elements used to measure emissions from fuel or direct measurement are missing, such that more than 20 percent of annual emissions cannot be directly calculated, a nonconformance occurs for the emissions source. The missing data must still be substituted as specified in 40 CFR §98.395. For the purpose of applying this provision, data substituted using an approved interim data collection procedure will be considered captured data and not count toward the 20 percent missing data limitation.

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

§ 95122. Suppliers of Natural Gas, Natural Gas Liquids, and Liquefied Petroleum Gas.

Any supplier of natural gas or natural gas liquids who is required to report under section 95101 must comply with Subpart NN of 40 CFR Part 98 (§§98.400 to 98.408) in reporting annual emissions to ARB, except as otherwise provided in this section.

(a) *GHGs to Report.*

(1) In addition to the CO_2 emissions specified under 40 CFR §98.402(a), natural gas liquid fractionators must report the CO_2, CH_4, N_2O and CO_2e emissions that would result from the complete combustion or oxidation of liquefied

petroleum gas sold or delivered to others, except for products for which a final destination outside California can be demonstrated.

(2) In addition to the CO_2 emissions specified under 40 CFR §98.402(b), local distribution companies must report the CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e emissions from the complete combustion or oxidation of the annual volume of natural gas provided to all entities on their distribution systems in California

(3) The California consignee for liquefied petroleum gas 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 imported into the state, except for products for which a final destination outside California can be demonstrated.

(b) *Calculating GHG Emissions.*

(1) Natural gas liquid fractionators must use calculation methodology 1 as specified in 40 CFR §98.403(a)(1) or calculation methodology 2 as specified in 40 CFR §98.403(a)(2) to estimate the CO_2 emissions that would result from the complete combustion of the product supplied. For calculating the emissions from liquefied petroleum gas, the fractionators must sum the emissions from the individual constituents. For components of liquefied petroleum gas not listed in Table NN-1 of 40 CFR 98, values from Tables MM-1 and C-1 of 40 CFR 98 must be used as appropriate.

(2) Local distribution companies must estimate CO_2 emissions at the state border or city gate for pipeline quality natural gas using calculation methodology 1 as specified in 40 CFR §98.403(a)(1), using the reporter specific weighted yearly average higher heating value and a default or reporter specific CO_2 emission factor. Receipts of pipeline quality natural gas from in-state natural gas producers and net volume of pipeline quality natural gas injected into storage are estimated according to 40 CFR §98.403(b)(3) using reporter specific emission factors. For 40 CFR §98.403(b)(3), reporter specific emission factors will be calculated as the product of the local distribution company's own weighted yearly average HHV measurement and the default emission factor, from Table NN-1 of 40 CFR Part 98, or reporter specific CO_2 emission factor for natural gas. Alternatively, local distribution companies may estimate CO_2 emissions from pipeline quality natural gas at the city gate as the sum of the products of the volume of gas received at each city gate and the reporter specific HHV measurement at the receipt location recorded at a minimum of a monthly frequency multiplied by the default emission factor from Table NN-1 of 40 CFR Part 98, or reporter specific CO_2 emission factor for natural gas. Receipts from in-state natural gas producers and net volume of natural gas injected into storage may also be estimated according to the above method. For natural gas outside the range of 970-1100 Btu/scf the local distribution company must estimate CO_2 emissions using the Tier 3 methodologies specified in 40 CFR §98.33(a)(3)(iii) with monthly carbon content samples

used to calculate the annual carbon content as specified in 40 CFR §98.33(a)(2)(ii)(A).

When calculating total CO_2 emissions for California, the equation below must be used:

$$CO_2 = \sum CO_{2i} - \sum CO_{2l}$$

Where:
CO_2 = Total emissions
CO_{2i} = Emissions from natural gas received at the state border or city gate
CO_{2l} = Emissions from storage and direct deliveries from producers

For the purpose of this section, a public utility gas corporation may use the California border as the city gate.

(3) Natural gas liquid fractionators and local distribution companies 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) for all fuels where annual CO_2 emissions are required to be reported by 40 CFR §98.406 and this section. Local distribution companies must use the reporter specific weighted yearly average higher heating value when calculating emissions.

(4) Local distribution companies must separately and individually calculate end-user emissions of CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e by replacing CO_2 in the equation in section 95122(b)(2) with CH_4, N_2O, CO_2 from biomass-derived fuels, and CO_2e.

(5) 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. The consignee must sum the emissions from the individual components of the liquefied petroleum gas, to calculate the total emissions. For components of liquefied petroleum gas not listed in Table NN-1 of 40 CFR 98, values from Tables MM-1 and C-1 of 40 CFR 98 must be used as appropriate. 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.

(6) The California consignee for liquefied petroleum 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).

(7) All fuel suppliers in this section must also estimate CO_2e emissions using the following equation

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i$$

Where:
CO_2e = Carbon dioxide equivalent, metric tons/year.
GHG_i = Mass emissions of CO_2, CH_4, N_2O from fuels combusted or oxidized.

GWP_i = Global warming potential for each greenhouse gas from Table A-1 of 40 CFR Part 98.

n = Number of greenhouse gases emitted.

(c) *Monitoring and QA/QC Requirements.* For each emissions calculation method chosen under this section, the supplier must meet all monitoring and QA/QC requirements specified in 40 CFR §98.404, except as modified in sections 95103, 95115, and below.

(1) All natural gas suppliers must measure required values at least monthly.
(2) All natural gas suppliers must determine reporter specific HHV at least monthly, or if the local distribution company does not make its own measurements according to standard business practices it must use the delivering pipeline measurement.
(3) All natural gas liquid fractionators must sample for composition at least monthly.
(4) All California consignees of liquefied petroleum gas must record composition, if provided by the supplier, and quantity in barrels, corrected to 60 degrees Fahrenheit, for each shipment received.

(d) *Data Reporting Requirements.*

(1) For the emissions calculation method selected under section 95122(b), natural gas liquid fractionators must report, in addition to the data required by 40 CFR §98.406(a), the annual volume of liquefied petroleum gas, corrected to 60 degrees Fahrenheit, sold or delivered to others, except for products for which a final destination outside California can be demonstrated. Natural gas liquid fractionators must report the annual quantity of liquefied petroleum gas delivered to others 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. Fractionators must also include the annual CO_2, CH_4, N_2O, and CO_2e mass emissions (metric tons) from the volume of liquefied petroleum gas reported in 40 CFR §98.406(a)(5) as modified by this regulation, calculated in accordance with section 95122(b)(1)-(3).
(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:

    (A) Publicly-owned natural gas utilities that report in-state receipts at the city gate under 40 CFR §98.406(b)(1) must also identify each delivering entity by name and report the monthly volumes received in Mscf and the monthly weighted average HHV.
    (B) Local distribution companies that report under 40 CFR §98.406(b)(1) through (b)(7) must also report the annual energy of natural gas in MMBtu associated with the volumes.

(C) In addition to the requirements in 40 CFR §98.406(b)(8), local distribution companies must also include CO_2, CO_2 from biomass-derived fuels, CH_4, N_2O, and CO_2e annual mass emissions in metric tons calculated in accordance with 40 CFR §98.403(a) and (b)(1) through (b)(3) as modified by section 95122(b).

(D) For each publicly-owned natural gas utility, local distribution companies must report the monthly volumes, monthly weighted average HHV, 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).

(E) For each customer, local distribution companies that report under 40 CFR §98.406 (b)(7) must report the annual volumes in Mscf, annual energy in MMBtu, and customer information required in 40 CFR §98.406(b)(12).

(F) Local distribution companies that report under 40 CFR §98.406(b)(9) must report annual CO_2, CO_2 from biomass-derived fuel, CH_4, N_2O, and CO_2e emissions (metric tons) that would result from the complete combustion or oxidation of the natural gas supplied to all entities calculated in accordance with section 95122(b)(2), (b)(4), and (b)(7).

(3) In addition to the information required in 40 CFR §98.3(c), the operator of non-utility interstate pipelines must report the customer name, address, and customer number along with monthly volumes of natural gas, in Mscf, and the corresponding weighted average monthly HHV in Btu/scf for natural gas delivered to each end user or wholesale customer, including themselves.

(4) In addition to the information required in 40 CFR §98.3(c), the operator of an intrastate pipeline not subject to Subpart NN of 40 CFR Part 98 that delivers natural gas directly to end users or wholesale customers must follow the reporting requirements described under Subpart NN and this section for local distribution companies. In lieu of the information specified by 40 CFR §98.406(b)(1), the operator must report volumes (Mscf) of natural gas received by the intrastate pipeline from interconnects with local distribution companies, interstate pipelines, or other intrastate pipelines.

(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).

(e) *Procedures for estimating missing data.* Suppliers must follow the missing data procedures specified in 40 CFR §98.405. The operator must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105. If any combination of data elements used to measure emissions from fuel or direct measurement is missing, such that more than 20 percent of annual emissions cannot be directly calculated, a nonconformance occurs for the emissions source. The missing data must still be substituted as specified in this section. For the purpose of applying this provision, data substituted using an approved interim data collection procedure will be considered captured data and not count toward the 20 percent missing data limitation.

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

§ 95123. Calculation Methods for Suppliers of Carbon Dioxide.

Any supplier of carbon dioxide who is required to report under section 95101 of this article must comply with Subpart PP of 40 CFR Part 98 (§§98.420 to 98.428) in reporting to ARB, except as otherwise provided in this section.

(a) When reporting imported and exported quantities of CO_2 as required in 40 CFR §98.422, the supplier must also report quantities of carbon dioxide imported into or exported from the State of California.

(b) *Missing Data Substitution Procedures.* The supplier must comply with 40 CFR §98.165 when substituting for missing data, except as otherwise provided below.

(1) For all data required for emissions calculations in this section, the supplier must follow the requirements of paragraphs (A)-(D) below.

(A) If the data capture rate is at least 90 percent for the data year, the supplier must substitute each missing value using the best available estimate of the parameter, based on all available process data.

(B) If the data capture rate is at least 80 percent but not at least 90 percent for the data year, the supplier must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the data capture rate is less than 80 percent for the data year, the supplier must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

(D) The supplier must document and retain records of the procedure used for all missing data estimates pursuant to the recordkeeping requirements of section 95105.

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

Subarticle 3
Additional Requirements for Reported Data

§95125. Additional Calculation Methods.

[Repealed]

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

In lieu of the requirements for estimating missing data in Subparts C and D of 40 CFR Part 98, the operator of a facility who is reporting emissions under section 95115 or 95112 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must follow the applicable procedures of this section for estimating missing or invalid data. The operator must include the substituted data in the GHG emissions data report and maintain all records, calculations, and data used to estimate substituted data according to the requirements of section 95105 and 40 CFR Part 98. Alternatively, under the limited circumstances specified in this section for equipment breakdown, the operator may request approval of an interim data collection procedure as specified in paragraphs 95129(h)-(i). For units combusting pure biomass-derived fuels, the operator who is reporting emissions must follow either the requirements below or the requirements of 40 CFR §98.35.

(a) *Missing Data Substitution Procedures for Units Reporting Under 40 CFR Part 75.* The operator of a unit that is subject to reporting under 40 CFR Part 75 must follow the applicable missing data substitution procedures in Part 75 for CO_2 concentration, stack gas flow rate, fuel flow rate, high heat value, and fuel carbon content. Paragraphs (b) through (g) of this section do not apply to these units.

(b) *Missing Data Substitution Procedures for Other Units Equipped with CEMS.* The operator of a stationary combustion unit who monitors and reports emissions and heat input data for that unit under section 95115 of this article using Tier 4 of Subpart C (40 CFR §98.33(a)(4)) must follow the applicable missing data substitution procedures in 40 CFR Part §75.31 to 75.37 (revised as of July 1, 2009).

(c) *Missing Data Substitution Procedures for Fuel Characteristic Data.* When the applicable emissions estimation methods of this article require periodic collection of fuel characteristic data (including carbon content, high heat value, and molecular weight) the operator must demonstrate every reasonable effort to obtain a fuel characteristic data capture rate of 100 percent for each data year. When fuel characteristic data of a required fuel sample are missing or invalid, the operator must first attempt to either reanalyze the original sample or perform the fuel analysis on a backup sample, or replacement sample from the same collection period as specified in 40 CFR §98.34(a)(2)-(3), to obtain valid fuel characteristic data. If the sample collection period has elapsed and no valid fuel characteristic data can be obtained from a backup or replacement sample, the operator must substitute for the missing data the values obtained according to the procedures in paragraphs

95129(c)(1)-(3). The data capture rate for the data year must be calculated as follows for each type of fuel and each fuel characteristic parameter:

Data capture rate = S / T x 100%

Where:
S = Number of fuel samples for which valid fuel characteristic data were obtained according to the applicable sampling requirements (including sampling schedule)
T = Total number of fuel samples required by the applicable sampling requirements

(1) If the fuel characteristic data capture rate is at least 90.0 percent for the data year, the operator must substitute the arithmetic average of the values of that parameter immediately preceding and immediately following the missing data incident that are representative of the fuel type. If the "after" value has not been obtained by the time that the GHG emissions data report is due, the operator must use the "before" value for missing data substitution.
(2) If the fuel characteristic data capture rate is at least 80.0 percent but not more than 90.0 percent for the data year, the operator must substitute for each missed value with the highest valid value recorded for that type of fuel during the data year as well as the two previous data years.
(3) If the operator is unable to obtain fuel characteristic data such that less than 80.0 percent of emissions from a source are directly accounted for, a nonconformance results for the emissions source. The operator must then substitute for each missed data point the greater of the following:

    (A) the highest valid value recorded for that type of fuel for all records kept under the requirements of section 95105, or
    (B) the default value in Table 1 of this section (for carbon content) or Table C-1 of 40 CFR Part 98 (for high heat value). If a substitute value is not available in Table 1 of this section or Table C-1 of 40 CFR Part 98, the operator must substitute the highest value recorded for that type of fuel for all records kept pursuant to the requirements of section 95105.

Table 1. Default Carbon Content

Parameter	Missing Data Value
Anthracite Coal	*90%*
Bituminous	*85%*
Subbituminous/Lignite	*75%*
Oil	*90%*
Natural Gas	*75%*
Other Gaseous Fuels	*90%*

(d) *Missing Data Substitution Procedures for Fuel Consumption Data.* For each fuel type, when annual fuel consumption data that meet the accuracy requirements of this article are available at the facility level, but such data are missing or invalid at the unit level, the operator must either estimate missing unit-level fuel consumption data using available process data that are routinely measured at the facility (e.g., electrical load, steam production, operating hours), or use an applicable missing data substitution procedure from paragraphs 95129(d)(1)-(3). If a portion of annual fuel consumption data at the facility level is missing or cannot be determined at the accuracy required by this article, the operator must use the applicable missing data substitution procedure from paragraphs 95129(d)(1)-(3) below.

(1) *Continuous Fuel Flow Rate Data Using Load Ranges.* The requirements of this paragraph apply to sources that combust gaseous or liquid fuels, produce electrical or thermal output, use a fuel flowmeter system to continuously measure fuel flow rate; and are equipped with a data acquisition and handling system (DAHS) that continuously records fuel flow rates and measured electrical or thermal output on an hourly basis, which enables segregation of the fuel flow rate data into bins. The operator of such sources must substitute missing fuel flow rate data according to this paragraph.

Whenever quality-assured fuel flow rate data are missing and there is no backup system available to record the fuel flow rate, the operator must use the following procedures to account for the flow rate of fuel combusted at the source for each hour during the missing data period. Before using these procedures, operators must establish load ranges for the affected sources using the procedures in paragraph (f) of this section.

When load ranges are used for estimating missing fuel flow rate data, the operator must create and maintain separate fuel-specific databases for the source. The database for each type of fuel combusted must include the hours in which the fuel is combusted alone at the source and the hours in which it is co-fired with any other fuel types. The database must record fuel flow rate and corresponding electrical output or thermal output, and assign these values into the established load bins. To be eligible to use the missing data procedures in this paragraph, measured electrical output or thermal output must be available for the hour(s) in which fuel flow rate data are missing. If output data are missing, the operator must follow the requirements of paragraph (d)(3).

(A) *Single Fuel Type.* For missing data periods that occur when only one type of fuel is being combusted, the operator must provide substitute data for each hour of the missing data period as follows: Substitute the arithmetic average of the hourly quality-assured fuel flow rate(s) measured and recorded by a fuel flowmeter system at the corresponding operating source load range during the previous 720 operating hours in which the source combusted only that same fuel. If 720 hours of fuel flow rate data are not available at the corresponding load range, the operator may combine available data with data from higher load ranges if available until 720 hours are reached. If 720 hours of quality-assured fuel flow rate data are not available when combined with higher load ranges, the operator must substitute the maximum potential fuel flow rate for each hour of the missing data period.

(B) *Multiple Fuel Types.* For missing data periods that occur when two or more different types of fuel are being co-fired, the operator must provide substitute fuel flow rate data for each hour of the missing data period as follows:

1. Substitute the maximum hourly quality-assured fuel flow rate(s) measured and recorded by a fuel flowmeter system at the corresponding operating source load range during the previous 720 operating hours when the fuel for which the flow rate data are missing was co-fired with any other type of fuel. If 720 hours of fuel flow rate data are not available at the corresponding load range, data from higher load ranges if available may be combined until 720 hours are reached. If 720 hours of quality-assured fuel flow rate data are not available when combined with higher load ranges, the operator must substitute the maximum potential fuel flow rate for each hour of the missing data period.
2. If, during an hour in which different types of fuel are co-fired, quality-assured fuel flow rate data are missing for two or more of the fuels being combusted, apply the procedures in subparagraph (d)(1)(B)1. separately for each type of fuel.
3. If the missing data substitution required in subparagraphs (d)(1)(B)1.-2. causes the reported hourly heat input rate based on the combined fuel usage to exceed the maximum rated hourly heat input of the unit, adjust the substitute fuel flow rate value(s) so that the reported heat input rate equals the unit's maximum rated hourly heat input.

(C) *Lookback Period.* In any case where the missing data provisions of this section require substitution of data measured and recorded more than three years (26,280 clock hours) prior to the date and time of the missing data period, the operator must substitute the maximum potential fuel flow rate for each hour of the missing data period. In addition, for sources in operation less than three years (26,280 clock hours), until 720 hours of quality-assured fuel flowmeter data are available for the lookback periods described in subparagraphs (d)(1)(A) and (d)(1)(B), the methodology in section (d)(3) must be used to determine the appropriate substitute data values.

(2) *Fuel Consumption Data Without Load Ranges.* This paragraph applies to fuel combusting units that cannot use the missing data procedures in paragraph (d)(1). Whenever quality-assured fuel consumption data are missing and there is no backup system available to record the fuel consumption, the operator must use the procedures in this paragraph to account for the consumption of fuel combusted at the unit during the missing data period. To be eligible to use the missing data procedures in this paragraph (d)(2), the

operator must monitor and keep records of fuel consumption on a regular basis. For fuels that are combusted less than 180 days in a calendar year, the operator must record fuel consumption at least daily on each day the fuel is combusted. For all other sources or fuels, the operator must record fuel consumption at least weekly.

The data capture rate for the data year must be calculated as follows for each unit with missing fuel consumption data:

Data capture rate = S / T x 100%

Where:

S = Number of fuel monitoring periods (e.g., days or weeks) in the data year for which valid measured fuel consumption data are available. Do not include fuel monitoring periods when the fuel was not combusted at the unit.

T = Total number of fuel monitoring periods (e.g., days or weeks) that the unit is operated in the data year.

(A) *Single Fuel.* For missing data periods that occur when only one type of fuel is being combusted, the operator must provide substitute data for each missing data period as follows:

1. If the fuel consumption data capture rate is equal to or greater than 95.0 percent during the data year, the operator must develop an estimate based on available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, operating hours).
2. If the fuel consumption data capture rate is equal to or greater than 90.0 percent but less than 95.0 percent during the data year, the operator must calculate substitute data as the 90^{th} percentile value of the fuel consumption data recorded for the data year as well as the two previous data years.
3. If the fuel consumption data capture rate is at least 80.0 percent but less than 90.0 percent during the data year, the operator must calculate substitute data as the 95^{th} percentile value of the fuel consumption data recorded for the data year as well as the two previous data years.
4. If the fuel consumption data capture rate is less than 80.0 percent during the data year, a nonconformance occurs for the emissions source, and the operator must apply as substitute data the maximum potential fuel consumption rate.

(B) *Multiple Fuels.* For missing data periods that occur when two or more different types of fuel are being co-fired, the operator must provide substitute fuel flow rate data for each missing data period as follows:

1. If the fuel consumption data for a single fuel are missing, provide substitute fuel consumption data for the missing data period using the procedures in paragraph 95129(d)(2)(A).
2. If fuel consumption data are missing for two or more of the fuels being combusted, apply the procedures in section 95129(d)(2)(A) (as applicable) separately for each type of fuel.
3. If the missing data substitution required in section 95129(d)(2)(A)causes the reported heat input rate based on the combined fuel usage to exceed the maximum rated heat input of the source, adjust the substitute fuel consumption value(s) so that the reported heat input rate equals the source's maximum rated heat input.

(C) *Prorating Substitute Value.* When applying the procedures in subparagraphs (d)(2)(A)-(B), if an individual missing data period is shorter than the fuel consumption data monitoring period, the operator must prorate the specified value for the fuel consumption data monitoring period by the missing data period. For example, for a unit with a missing data period length of one day but weekly fuel consumption monitoring schedule, the operator may divide the substitute value, estimated on a weekly basis, by the number of days the unit operates in a week to obtain the substitute value for the missing data day.

(3) *Alternate Missing Data Procedure for Fuel Consumption Data.* This paragraph applies to fuel combusting units that cannot use the missing data procedures in paragraphs (d)(1) and (d)(2). If fuel consumption data are missing or invalid for a fuel combusting unit, and fuel consumption data at the facility level or aggregated unit level cannot be determined at the accuracy required by this article, the operator must substitute for each hour of missing data using the maximum potential fuel consumption rate for the unit. If fuel consumption data at the facility level or at a higher aggregated-units level are available and meet the accuracy requirements of this article, the operator may estimate the missing unit-level fuel consumption data using available process data that are routinely measured at the facility (e.g., electrical load, steam production, operating hours).

(e) *Missing Data Substitution Procedures for Steam Production.* The operator of a steam-producing unit who calculates and reports emissions using Equation C-2c in 40 CFR §98.33(a)(2) must apply the procedures in this paragraph to substitute for missing steam production data, unless a backup system to record steam production is available. For sources for which steam production data are not used to calculate emissions, the operator may develop an estimate using available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, product output, operating hours) to estimate missing steam production.

If hourly steam production data are not available at the facility, the operator must record steam production data at least weekly and use the weekly records for substituting the missing steam production data. The operator must prorate the steam data using the same procedure in paragraph (d)(2)(C).

The data capture rate for the data year must be calculated as follows for each unit with a missing data period:

Data capture rate = S / T x 100%

Where:

S = Number of monitoring intervals (e.g. hourly, daily, or weekly) with valid measured steam production data.

T = Total number of monitoring intervals that the unit is operated in the data year.

(1) If the steam production data capture rate is at least 90.0 percent during the data year, the operator must develop an estimate using available process data that are routinely measured and recorded at the unit (e.g., electrical load, steam production, product output, and operating hours).

(2) If the steam production data capture rate is at least 80.0 percent but less than 90.0 percent during the data year, the operator must calculate substitute data as the 90^{th} percentile value of the steam production data recorded for the data year.

(3) If the steam production data capture rate is less than 80.0 percent during the data year, a nonconformance occurs for the emissions source, and the operator must substitute the highest valid steam production value recorded in all records kept according to section 95105(a).

(f) *Procedure for Establishing Load Ranges.* This paragraph is applicable to units that produce electrical output or thermal output. For a single unit, the operator must establish ten operating load ranges, each defined in terms of percent of the maximum hourly average gross load of the unit, in gross megawatts (MW). (Do not use integrated hourly gross load in MWh.) For a cogenerating unit or other unit at which some portion of the heat input is not used to produce electricity, or for a unit for which hourly average gross load in MW is not recorded separately, the operator must use the hourly gross steam load of the unit, in pounds of steam per hour at the measured temperature (°F) and pressure (psia), instead of gross MW.

Beginning with the first hour of unit operation after installation and certification of the fuel flowmeter, for each hour of unit operation the operator must record a number, 1 through 10, that identifies the operating load range corresponding to the integrated hourly gross load of the unit(s) recorded for each unit operating hour. The operator must calculate maximum values and percentile values determined by this procedure using bias adjusted values in the load ranges. When a bias adjustment is necessary for the fuel flowmeter, the operator must apply the adjustment factor to all data values placed in the load ranges. The operator must use the calculated maximum values and percentile values to substitute for missing flow rate according to the procedures in paragraph (d)(1) of this section.

(g) *Executive Officer Approved Load Range.* An operator may petition the Executive Officer for approval to use an alternate load based methodology for substituting missing data to using the procedures in paragraph 95129(d)(1). The operator must be able to prove to the satisfaction of the Executive Officer that there is a direct correlation between fuel consumption and the proposed load metric. At a minimum, the operator will have a system in place that electronically measures and records fuel consumption and load at least hourly. The alternate load metric must be a metric that can be accurately measured, correlated to fuel consumption, and divided into ten operating load ranges. In order to verify the feasibility of the methodology the Executive Officer will require at least three years of fuel consumption and load data and may request up to the maximum years of data required to be retained under section 95105(a).

(h) *Procedure for Approval of Interim Fuel Analytical Data Collection Procedure During Equipment Breakdowns.*

(1) In the event of an unforeseen breakdown of the fuel characteristic data monitoring or fuel flow monitoring equipment used to estimate emissions under this article, the Executive Officer may authorize an operator to use an interim data collection procedure under the circumstances specified below. The operator must satisfactorily demonstrate to the Executive Officer that:

(A) The breakdown may result in a loss of more than 20 percent of a fuel characteristic or fuel usage data element for the data year, and back-up sampling for affected fuel characteristics is unavailable;
(B) The affected monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or the monitoring equipment must be replaced and replacement equipment is not immediately available; and,
(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning monitoring equipment.

(2) An operator seeking approval of an interim data collection procedure must, within sixty days of the monitoring equipment breakdown, submit a written request to the Executive Officer that includes all of the following:

(A) The proposed start date and end date of the interim procedure;
(B) A detailed description of what data are affected by the breakdown;
(C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the usual procedure used by the operator;

(D) A demonstration that the criteria in paragraph (h)(1) are satisfied, and operator certification that no feasible alternative procedure exists that would provide more accurate emissions data.

(3) The Executive Officer may limit the duration of the interim data collection procedure to ensure the criteria in paragraph (h)(1) are met.

(4) When reviewing an interim data collection procedure, the Executive Officer shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under section 95131 of this article. Data collected pursuant to an approved interim data collection procedure shall be considered captured data for purposes of compliance with the capture rate requirements in this section.

(5) The Executive Officer shall provide written notification to the operator of approval or disapproval of the interim data collection procedure within sixty days of receipt of the request, or within thirty days of receipt of any additional information requested by the Executive Officer, whichever is later.

(i) *Procedure for Approval of Interim Data Collection Procedure During Breakdown for Units Equipped with CEMS.*

(1) In the event of an unforeseen breakdown of CEMS equipment at a combustion unit where the operator uses the Tier 4 Calculation Methodology (40 CFR 98.33(a)(4)) to monitor and report emissions under this article, the operator may request approval from the Executive Officer to temporarily use the Tier 2 Calculation Methodology (40 CFR 98.33(a)(2)) for natural gas, biomass, or municipal solid waste, or the Tier 3 Calculation Methodology (40 CFR 98.33(a)(3)) for other fuels, to calculate emissions during the equipment breakdown period. The operator must satisfactorily demonstrate to the Executive Officer that:

(A) The breakdown will result in a loss of more than 20 percent of the concentration, flow rate, or other information used to calculate and report annual emissions for the data year, and that back-up monitoring is unavailable;

(B) The affected monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or the monitoring equipment must be replaced and replacement equipment is not immediately available; and,

(C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning monitoring equipment.

(2) The operator must collect fuel samples and comply with all applicable requirements of the Tier 2 or Tier 3 Calculation Methodology in 40 CFR

98.33(a)(2) or (3), as modified by section 95115 of this article, during the equipment breakdown period. Fuel characteristics data provided by the fuel suppliers can be used if available. The operator must, within sixty days of the monitoring equipment breakdown, submit a written request to the Executive Officer that includes all the following information:

(A) The proposed start date and end date of the interim procedure, including a demonstration that the interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning equipment;
(B) A detailed description of what data are affected by the breakdown; and,
(C) An interim monitoring plan that meets the requirements of the Tier 3 Calculation Methodology as applicable by fuel type in section 95115.

(3) The Executive Officer may limit the duration of the interim data collection procedure to ensure the criteria in paragraph (i)(1) are met.
(4) The Executive Officer shall provide written notification to the operator of approval or disapproval of the interim data collection procedure within sixty days of receipt of the request, or within thirty days of receipt of any additional information requested by the Executive Officer, whichever is later.

(j) *Cumulative Missing Data Elements.* If any combination of data elements used to measure emissions from fuel or direct measurement is missing, such that more than 20 percent of annual emissions cannot be calculated from directly measured data, a nonconformance occurs for the emissions source. The missing data must still be substituted as specified in this section. For the purpose of applying this provision, data substituted using an approved interim data collection procedure will be considered captured data and not count toward the 20 percent missing data limitation.

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

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

§ 95130. Requirements for Verification of Emissions Data Reports.

The reporting entity who is 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).

(a) *Annual Verification.*

(1) Reporting entities required to obtain annual verification services as specified in section 95103(f) are subject to full verification requirements in the first year that verification is required in each compliance period. Upon receiving a positive verification statement under full verification requirements, the reporting entity may choose to obtain less intensive verification services for the remaining years of the compliance period. Full verification requirements shall apply at least once in each compliance period. Reporting entities subject to this section are required to obtain full verification services if any of the following apply:

(A) The emissions data report is for the 2011 data year;
(B) There has been a change in the verification body;
(C) An adverse verification statement or qualified positive verification statement was issued for the previous year;
(D) A change of ownership of the reporting entity occurred in the previous year;
(E) The total reported GHG emissions during the data year differs by greater than 25 percent relative to the preceding emission data report;
(F) The total reported MWh during the data year differs by greater than 25 percent relative to the preceding emission data report;

(2) Reporting entities subject to annual verification under section 95130 shall not use the same verification body or verifiers(s) for a period of more than six consecutive years, which includes any verifications conducted under this article and for the California Climate Action Registry, The Climate Registry, or Climate Action Reserve. If a reporting entity is required or elects to contract with another verification body or verifier(s), the reporting entity may contract verification services from the previous verification body or verifier(s) only after not using the previous verification body or verifiers(s) for at least three years.

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

§ 95131. Requirements for Verification Services.

Verification services shall be subject to the following requirements.

(a) *Notice of Verification Services.* After the Executive Officer has provided a determination that the potential for a conflict of interest is acceptable as specified in section 95133(f) and that verification services may proceed, the verification body shall submit a notice of verification services to ARB. The verification body may begin verification services for the reporting entity ten working days after the notice is received by the Executive Officer, or earlier if approved by the Executive Officer in writing. In the event that the conflict of interest statement and the notice of verification services are submitted together, verification services cannot begin until ten working days after the Executive Officer has deemed acceptable the potential for conflict of interest as specified in 95133(f). The notice shall include the following information:

(1) A list of the staff who will be designated to provide verification services as a verification team, including the names of each designated staff member, the lead verifier, and all subcontractors, and a description of the roles and responsibilities each member will have during verification. If any staff change on the verification team, that information must be updated and resubmitted to ARB five days before the verification services begin with the reporting entity;

(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 to provide sector specific verification services when required below:

(A) For providing verification services to an electric power entity, a supplier of petroleum products or biofuels, a supplier of natural gas, natural gas liquids, or liquefied petroleum gas, or a supplier of carbon dioxide, at least one verification team member must be accredited by ARB as a transactions specialist;

(B) For providing verification services to the operator of a petroleum refinery, hydrogen production unit or facility, or petroleum and natural gas system listed in section 95101(e), at least one verification team member must be accredited by ARB as an oil and gas systems specialist;

(C) For providing verification services to the operator of a facility engaged in cement production, glass production, lime manufacturing, pulp and paper manufacturing, iron and steel production, or nitric acid production, at least one verification team member must be accredited by ARB as a process emissions specialist.

(3) General information on the reporting entity, including:

(A) The name of the reporting entity and the facilities and other locations that will be subject to verification services, reporting entity contact, address, telephone number, and e-mail address;
(B) The industry sector and the North American Industry Classification System (NAICS) code for the reporting facility;
(C) The date(s) of the on-site visit, with facility address and contact information;
(D) A brief description of expected verification services to be performed, including expected completion date.

(4) If any of the information under section 95131(a)(1) or 95131(a)(3) changes after the notice is submitted to ARB, the verification body must notify ARB at least five days before the verification services start date. If any information submitted under section 95131(a)(1) or 95131(a)(3) changes during the verification services, the verification body must notify ARB before the verification statement is provided to ARB.

(b) Verification services shall include, but are not limited to, the following:

(1) *Verification Plan.* The verification team shall obtain information from the reporting entity necessary to develop a verification plan. Such information shall include, but is not limited to:

(A) Information to allow the verification team to develop a general understanding of facility or entity boundaries, operations, emissions sources, and electricity or fuel transactions as applicable;
(B) Information regarding the training or qualifications of personnel involved in developing the emissions data report;
(C) Description of the specific methodologies used to quantify and report greenhouse gas emissions, electricity and fuel transactions, and associated data as needed to develop the verification plan;
(D) Information about the data management system used to track greenhouse gas emissions, electricity and fuel transactions, and associated data as needed to develop the verification plan.

(2) The verification team shall develop a verification plan that includes, at a minimum:

(A) Dates of proposed meetings and interviews with reporting facility personnel;
(B) Dates of proposed site visits;
(C) Types of proposed document and data reviews;
(D) Expected date for completing verification services.

(3) The verification team shall discuss with the reporting entity the scope of the verification services and request any information and documents needed for initial verification services. The verification team shall review the documents submitted and plan and conduct a review of original documents and supporting data for the emissions data report.

(4) *Site visits.* At least one accredited verifier in the verification team, including the sector specialist, 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:

   (A) The verification team member(s) shall check that all sources specified in sections 95110 to 95123, and 95150 to 95158, as applicable to the reporting entity are identified appropriately.

   (B) The verification team member(s) shall review and understand the data management systems used by the reporting entity to track, quantify, and report greenhouse gas emissions and, when applicable, electricity and fuel transactions. The verification team member(s) shall evaluate the uncertainty and effectiveness of these systems.

   (C) The verification team shall carry out tasks that, in the professional judgment of the team, are needed in the verification process, including the following:

      1. Interviews with key personnel, such as process engineers and metering experts, as well as staff involved in compiling data and preparing the emissions data report;
      2. Making direct observations of equipment for data sources and equipment supplying data for sources determined in the sampling plan to be high risk;
      3. Assessing conformance with fuel analytical data requirements including: fuel meter accuracy requirements, data capture, and missing data substitution requirements;
      4. Reviewing financial transactions to confirm fuel and electricity purchases and sales.

(5) The verification team shall review facility operations to identify applicable greenhouse gas emissions sources. This shall include a review of the emissions inventory and each type of emission source to ensure that all sources listed in sections 95110 to 95123 and sections 95150 to 95158 of this article are properly included in the emissions data report.

(6) Reporting entities shall make available to the verification team all information and documentation used to calculate and report emissions, fuels and electricity transactions, and other information required under this article, as applicable.

(7) For electricity importers and exporters, the verification team shall review electricity transaction records, including receipts of power attributed to the Northwest or Southwest region as verifiable via North American Electric Reliability Corporation (NERC) E-Tags, settlements data, or other information as confirmation of the region of origin.

(8) *Sampling Plan.* As part of confirming emissions data, electricity transactions, or fuel transactions the verification team shall develop a sampling plan that meets the following requirements:

(A) The verification team shall develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale and complexity of the verification services for a reporting entity. The analysis shall review the inputs for the development of the submitted emissions data report, the rigor and appropriateness of data management systems, and the coordination within the reporting entity's organization to manage the operation and maintenance of equipment and systems used to develop emissions data reports.

(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. 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.

(C) The verification team shall include in the sampling plan a qualitative narrative of uncertainty risk assessment in the following areas as applicable under sections 95110 to 95123, 95129, and 95150 to 95158:

1. Data acquisition equipment;
2. Data sampling and frequency;
3. Data processing and tracking;
4. Emissions calculations;
5. Data reporting;
6. Management policies or practices in developing emissions data reports.

(D) After completing the analyses required by sections 95131(b)(8)(A)-(C), the verification team shall include in the sampling plan a list which includes the following:

1. Emissions sources and/or transactions that will be targeted for document reviews, and data checks as specified in 95131(b)(9), and an explanation of why they were chosen;
2. Methods used to conduct data checks for each source or transaction;

3. A summary of the information analyzed in the data checks and document reviews conducted for each emissions source or transaction targeted.

The sampling plan list must be updated and finalized prior to the completion of verification services.

(E) The verification team shall revise the sampling plan to describe tasks completed by the verification team as relevant information becomes available and potential issues emerge with material misstatement or nonconformance with the requirements of this article.

(F) The verification body shall retain the sampling plan in paper, electronic, or other format for a period of not less than ten years following the submission of each verification statement. The sampling plan shall be made available to ARB upon request.

(G) The verification body shall retain all material received, reviewed, or generated to render a verification statement for a reporting entity for no less than ten years. The documentation must allow for a transparent review of how a verification body reached its conclusion in the verification statement.

(9) *Data Checks.* To determine the reliability of the submitted emissions data report, the verification team shall use data checks. Such data checks shall focus on the largest and most uncertain estimates of emissions and fuel and electricity transactions, and shall include the following:

(A) The verification team shall use data checks to ensure that the appropriate methodologies and emission factors have been applied for the emissions sources and fuel and electricity transactions covered under sections 95110 to 95123, 95129, and 95150 to 95158;

(B) The verification team shall choose for data checks emissions sources and fuel and electricity transactions data, as applicable, based on their relative contributions to emissions and the associated risks of contributing to material misstatement or nonconformance, as indicated in the sampling plan;

(C) The verification team shall use professional judgment in the number of data checks required for the team to conclude with reasonable assurance whether the total reporting entity reported emissions are free of material misstatement and the emissions data report otherwise conforms to the requirements of this article. At a minimum, data checks must include the following:

1. Tracing data in the emissions data report to its origin;
2. Looking at the process for data compilation and collection;
3. Recalculating emission estimates to check original calculations;

4. Reviewing calculation methodologies used by the reporting entity for conformance with this article; and
5. Reviewing meter and fuel analytical instrumentation measurement accuracy and calibration for consistency with the requirements of section 95103(k).

The verification team shall compare its own calculated results with the reported data in order to confirm the extent and impact of any omissions and errors. Any discrepancies must be investigated. The comparison of data checks must provide enough detail to indicate which sources and transactions were checked, the types and quantity of data that were evaluated for each source and transaction, and any discrepancies that were identified.

(10) *Emissions Data Report Modifications.* As a result of data checks by the verification team and prior to completion of a verification statement, 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. 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.

(11) *Findings.* To verify that the emissions data report is free of material misstatement, the verification team shall make its own determination of emissions for checked sources and shall determine whether there is reasonable assurance that the emissions data report does not contain a material misstatement for the reporting entity, on a CO_2 equivalent basis for GHG emissions. 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) *Log of Issues.* The verification team must keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance. The issues log must identify the regulatory section related to the nonconformance, if applicable, and indicate if the issues were corrected by the reporting entity prior to completing the verification. Any other concerns that the verification team has with the preparation of the emissions data report, including with any *de minimis* method calculations, must be documented in the issues log. The log of issues must indicate whether each issue has a potential bearing on material misstatement, nonconformance, or both.

(13) An assessment of material misstatement is conducted on total reported GHG emissions (metric tons of CO_2e), except those emissions without a compliance obligation as set forth in title 17, California Code of Regulations, section 95852.2.

(14) In assessing whether an emissions data report contains a material misstatement, the verification team must determine whether the total reported emissions contain a material misstatement using the following equation:

$$Percent\ accuracy = 100\% - \sum \frac{[Errors + Omissions + Misreporting]\ x\ 100\%}{Total\ reported\ emissions}$$

Where:
"Errors" means any differences between the reported emissions and verifier calculated emissions for a data source subject to data checks in 95131(b)(9).

"Omissions" means any emissions 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 emissions the verifier concludes should, or should not, be part of the emissions data report.

"Total reported emissions" means the total annual reporting entity CO2e emissions reported for the emission sources which hold a compliance obligation as set forth in title 17, California Code of Regulations, sections 95852 and 95852.1 for which the verifier is conducting a material misstatement assessment.

(15) The verification team must check the following for conformance as part of verifier review with the reporting requirements under this article, when applicable data checks are chosen under 95131(b)(9), but does not have to conduct a material misstatement assessment using the equation in 95131(b)(14);

(A) Total reported facility indirect electricity purchases (kWH);
(B) Total reported facility indirect thermal purchases (Btu);
(C) Total reported GHG emissions (metric tons of CO_2e) included in the emissions data report as emissions without a compliance obligation under title 17, California Code of Regulations, section 95852.2.

(16) *Review of Missing Data Substitution.* If a source selected for a data check was affected by a loss of data used to calculate GHG emissions for the data year:

(A) The verification team shall confirm that the reported emissions for that source were calculated using the applicable missing data procedures, or that an approved interim data collection procedure was used for the source.

(B) The difference between the reporting entity's calculated emissions and verifier's calculated emissions for that source will be zero when assessing for material misstatement under section 95131(b)(14), when the applicable missing data substitution procedures or interim data collection procedure has been correctly applied by the reporting entity; or, any relative accuracy assigned to the emissions estimate under section 95129(h)(4) has been correctly applied.

(C) If 20 percent or less of any combination of data elements used to measure emissions from fuel or direct measurement are missing, and emissions correctly calculated using the missing data requirements in sections 95110 to 95123, 95129, and 95150 to 95158 will be considered accurate and as meeting the reporting requirements for that source.

(D) If greater than 20 percent of the emissions for a source has been calculated from data that has been substituted according to the missing data provisions of this article, the verifier will note a non-conformance as part of the verification finding.

(c) Completion of verification services must include:

(1) *Verification Statement.* Upon completion of the verification services specified in section 95131(b), the verification body shall complete a verification statement, and provide that statement to the reporting entity and the ARB by the applicable verification deadline specified in section 95103(f). Before that statement is completed, the verification body shall have the verification services and findings of the verification team independently reviewed within the verification body by an independent reviewer who is a lead verifier not involved in services for that reporting entity during that year.

(2) The independent reviewer shall serve as a final check on the verification team's work to identify any significant concerns, including:

(A) errors in planning,
(B) errors in data sampling, and
(C) errors in judgment by the verification team that are related to the draft verification statement.

The independent reviewer must maintain independence from the verification services by not making specific recommendations about how the verification services should be conducted. The independent reviewer will review documents relevant to the verification services provided, and identify any failure to comply with requirements of this article or with the verification body's internal policies and procedures for providing verification services. The independent reviewer must concur with the verification findings before the verification statement can be issued.

(3) When the verification team completes its findings:

(A) The verification body shall provide to the reporting entity a detailed verification report. The detailed verification report shall at a minimum include the verification plan, the detailed comparison of the data checks conducted during verification services, the log of issues identified in the course of verification activities and their resolution, and any qualifying comments on findings during verification services. The detailed verification report shall also include the calculation performed in section 95131(b)(14). The detailed verification report shall be made available to ARB upon request.

(B) The verification team shall have a final discussion with the reporting entity explaining its findings, and notify the reporting entity of any unresolved issues noted in the issues log before the verification statement is finalized.

(C) The verification body shall provide the verification statement to the reporting entity and the ARB, attesting whether the verification body has found the submitted emissions data report to be free of material misstatement, and whether the emissions data report is in conformance with the requirements of this article. In the case of a qualified positive verification statement, the verification body shall explain the non-conformances contained within the emissions data report and why the non-conformances do not result in a material misstatement. In the case of an adverse verification statement, the verification body must explain all non-conformances and material misstatements leading to the adverse verification statement.

(D) The lead verifier in the verification team shall attest that the verification team has carried out all verification services as required by this article, and the lead verifier who has conducted the independent review of verification services and findings shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings.

(4) Prior to the verification body providing an adverse verification statement to the ARB, the reporting entity shall be provided at least ten working days to modify the emissions data report to correct any material misstatement or nonconformance found by the verification team. The modified report and verification statement must be submitted to ARB before the applicable verification deadline, unless the reporting entity makes a request to the Executive Officer as provided below in section 95131(c)(4)(A).

(A) If the reporting entity and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification statement or qualified positive verification statement because of a disagreement on the requirements of this article, the reporting entity may petition the ARB Executive Officer to make a final decision as to the verifiability of the submitted emissions data report.

(B) If the Executive Officer determines that the emissions data report does not meet the standards and requirements specified in this article, the reporting entity shall have the opportunity to submit within thirty days of the date of this decision any emissions data report revisions that address the Executive Officer's determination, for re-verification of the emissions data report. In re-verifying a revised emissions data report, the verification body and verification team shall be subject to the requirements in section 95131(c)(1)-(3), and must submit the revised verification statement to ARB within 15 days.

(5) *Assigned Emissions Level.* When a reporting entity fails to receive a positive or qualified positive verification statement for a data year by the applicable deadline, the Executive Officer shall develop an assigned emissions level for the data year for the reporting entity. Within ten days of a written request by the Executive Officer, the verification body (if applicable) shall provide any available verification services information or correspondence related to the emissions data. Within ten days of a request by the Executive Officer, the reporting entity shall provide the data that is required to calculate GHG emissions for the entity according to the requirements of this article, the preliminary or final detailed verification report prepared by the verification body (if applicable), and other information requested by the Executive Officer, including the operating days and hours of the reporting entity during the data year. The reporting entity shall also make available personnel who can assist the Executive Officer's determination of an assigned emissions level for the data year.

(A) In preparing the assigned emissions level for the reporting entity, the Executive Office shall consider at a minimum the following information:

1. The number, types and days and hours of operation of the sources operated by the reporting entity for the emissions data year;
2. Any previous emissions data reports submitted by the reporting entity and verification statements rendered for those reports;
3. The potential maximum fuel and process material input and output capacities for the reporting entity's emissions sources during operating hours;
4. For electric power entities, wholesale and retail transactions that would affect an assigned emissions level, for the relevant data year and for previous years;
5. Emissions, electricity transactions, fuel use, or product output information reported to ARB or other State, federal, or local agencies.

(B) The Executive Officer shall calculate the assigned emissions level for the reporting entity using the best information available, including the information in section 95131(c)(5)(A), as applicable. The reporting entity shall be provided at least 5 days to review and comment on the assigned emissions level.

(d) Upon provision of the verification statement to ARB, the emissions data report shall be considered final. No changes shall be made to the report as submitted to ARB, notwithstanding the requirements of 40 CFR §98.3(h), and all verification requirements of this article shall be considered complete except in the circumstance specified in section 95131(e).

(e) If the Executive Officer finds a high level of conflict of interest existed between a verification body and a reporting entity, or an emissions data report that received a positive or qualified positive verification statement fails an ARB audit, the Executive Officer may set aside the positive or qualified positive verification statement issued by the verification body, and require the reporting entity to have the emissions data report re-verified by a different verification body within 90 days.

(f) Upon request by the Executive Officer the reporting entity shall provide the data used to generate an emissions data report, including all data available to a verifier in the conduct of verification services, within 10 working days.

(g) Upon request of the Executive Officer the verification body shall provide ARB the full verification report given to the reporting entity, as well as the sampling plan and any other supporting documents and calculations, within 10 working days.

(h) Upon written notification by the Executive Officer, the verification body shall make its personnel available for an ARB audit.

(i) *Verifying Biomass-derived Fuels.* Requirements for providing verification services for biomass-derived fuels not subject to a compliance obligation as set forth in title 17, California Code of Regulations, Section 95852.2 In the absence of certification of the fuel by an accredited certifier of biomass-derived fuels, the verification body shall conduct the following requirements to verify a biomass-derived fuel that will not be subject to a compliance obligation:

(1) The verification body shall provide information assessing its potential for conflict of interest as set forth in section 95133(b),(c) and (d) with the reporting entity and each biomass-derived fuel entity in the chain of custody for that fuel as part of the conflict of interest submittal requirements in 95133(e)

(2) At least one accredited verifier in the verification team, including the transactions sector specialist, shall at a minimum make one site visit, during each year full verification is required, to each biomass-derived fuel entity in the chain of custody for that fuel. One member of the verification team must visit the headquarters or other location of central data management when the biomass-derived fuel entity is a marketer, distributor, or suppler and does not physically store or produce the fuel on-site and conduct the site visit as

required in section 95131(b)(4) for each biomass-derived fuel entity in the chain of custody for that fuel.

(A) The verification team members shall examine biomass-derived fuel contracts to determine that one of the two following conditions has been met:

1. That the contract for purchasing any biomass-derived fuel was in effect prior to January 1, 2010 and remains in effect or has been renegotiated for the same California operator within one year of contract expiration;
2. That the fuel being provided under a contract dated after January 1, 2010 is only for an amount of fuel that is associated with an increase in the biomass-based fuel producer's capacity.

   If a contract includes both fuel that does and does not meet this condition, then only the portion of the fuel that does meet this condition will be considered biomass-derived fuel.

(B) The verification team shall determine that no entity in the chain of custody has applied for or received credit for the use of biomass-derived fuel in offset credits or any other credit for greenhouse gas reductions in another voluntary or regulatory project.

(C) The verification team shall determine that any entity that produces biomass-derived fuels is doing so in accordance with the requirements of title 17, California Code of Regulations, section 95852.2.

(D) The verification team shall determine that an entity's total volume of biomass-derived fuel transferred to all customers in a calendar year does not exceed the entity's purchases and production of biomass-derived fuels during that year.

(E) The verification team must be able to track the exact amount of fuel indentified in contracts or invoices from the producer to the reporting entity, and have reasonable assurance that the reporting entity is the only customer receiving that fuel.

(F) The verification team shall review and evaluate all fuel analytical devices and data management systems used by biomass-derived fuel entities to quantify, track, and report fuel amounts. The verification team must evaluate the uncertainty and effectiveness of these systems using the requirements in section 95131(b)(8).

(G) Verifying fuel transactions shall include evaluating the measured and estimated fuel volumes, as well as any relevant information required to calculate emissions including composition, high heat value, carbon content, or supplier specific emission factors.

(3) If any biomass-derived fuel entity in the chain of custody does not make available to the verification team all the information and documentation

necessary to establish the validity of the reporting entity's claim of biomass-derived fuel purchase, the fuel purchase, as described in section 95131(i)(2)(B-G), will be considered unverifiable and be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852.1.

(4) To verify that the amount of biomass-derived fuel reported by a reporting entity is free of a material misstatement, the verification team shall determine whether there is reasonable assurance that the amount of biomass derived fuel purchased was actually produced and delivered, or injected into a transmission pipeline to the reporting entity, and any errors, omissions, or misreporting of the biofuels emissions do not result in a material misstatement. To assess conformance with this article, the verification team shall review the methods and factors used to calculate and report biomass-derived fuel amounts for adherence to the requirements of this article.

(5) Verification requirements specific to biomass-derived fuel producing facilities are as follows:

(A) The verification team shall establish that the biomass-derived fuel entity employs procedures for fuel data measurement with an accuracy within ±5 percent. All fuel analytical measurement devices shall be installed, maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy. If the documentation to support this level of accuracy is not provided to the verification team, then the fuel will be considered unverifiable and be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852.1.

(B) The verification team shall establish that the heating value of the biomass-derived fuel used in any transaction was appropriately calculated using the method required by section 95115(c).

(C) The verification team shall establish that the biomass-derived fuel entity retains at least 95% of its fuel production or fuel transaction data. If more than 5% of data is missing, the fuel will be considered unverifiable and be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852(g).

(6) If the verification body is unable to verify the biomass-based fuel to the above requirement, it will be considered unverifiable and be required to hold a compliance obligation under title 17, California Code of Regulations, section 95852.1.

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

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

(a) The accreditation requirements specified in this subarticle shall apply to all verification bodies, lead verifiers, and verifiers that wish to provide verification services under this article and under the Cap-and-Trade Regulation.

(b) The Executive Officer may issue accreditation to verification bodies, lead verifiers, and verifiers that meet the requirements specified in this section.

(1) *Verification Body Accreditation Application.* To apply for accreditation as a verification body, the applicant shall submit the following information to the Executive Officer:

(A) A list of all verification staff and a description of their duties and qualifications, including ARB accredited verifiers on staff. The applicant shall demonstrate staff qualifications by listing each individual's education, experience, professional licenses, and other pertinent information.

1. A verification body shall have and retain at least two verifiers that have been accredited as lead verifiers, as specified in section 95132(b)(2);
2. A verification body shall have and retain at least five total full-time staff.

(B) The applicant shall provide a list of any judicial proceedings or administrative actions filed against the body within the previous 5 years, with an explanation as to the nature of the proceedings.

(C) The applicant shall provide documentation that the proposed verification body maintains a minimum of four million U.S. dollars of professional liability insurance and must maintain this insurance for three years after completing verification services.

(D) The applicant shall provide a demonstration that the body has policies and mechanisms in place to prevent conflicts of interest and to identify and resolve potential conflict of interest situations if they arise. The applicant shall provide the following information:

1. Identification of services provided by the verification body, the industries that the body serves, and the locations where those services are provided;
2. A detailed organizational chart that includes the verification body, its management structure, and any related entities;

3. The verification body's internal conflict of interest policy that identifies activities and limits to monetary or non-monetary gifts that apply to all employees.

(E) The applicant shall provide a demonstration that the body has procedures or policies to support staff technical training as it relates to verification. This training shall include participating in ARB verifier training on an ongoing basis.

(F) The verification body shall notify ARB within 30 days of when it no longer meets the requirements for accreditation as a verification body in section 95132(b)(1). The verification body may request that the Executive Officer provide an additional time to hire additional staff to meet the minimum requirements of this section.

(G) If the applicant is a California air pollution control district or air quality management district, the requirements of section 95132(b)(1)(A)(2) and 95132(b)(1)(B)-(D) do not apply, except that the applicant shall provide a demonstration that the district has policies and mechanisms in place to prevent conflicts of interest and resolve potential conflict of interest situations if they arise.

(2) *Lead Verifier Accreditation Application*. To apply for accreditation as a lead verifier, the applicant shall submit documentation to the Executive Officer that provides the evidence specified in section 95132(b)(2)(A), and section 95132(b)(2)(B), or (C):

(A) Evidence that the applicant meets the criteria in 95132(b)(3); and,
(B) Evidence that the applicant has been an ARB accredited verifier for two continuous years and has worked as a verifier in at least three completed verifications under the supervision of an ARB accredited lead verifier, with evidence of favorable assessment by ARB for services performed; or,
(C) Evidence that at the time of the verification training examination, the applicant has worked as a project manager or lead person for not less than four years, of which two may be graduate level work:

1. In the development of GHG or other air emissions inventories; or,
2. As a lead environmental data or financial auditor in the private sector.

(3) *Verifier Accreditation Application.* To apply for accreditation as a verifier, the applicant shall submit the following documentation to the Executive Officer:

(A) Evidence demonstrating the minimum education background required to act as a verifier for ARB. Minimum education background means that the applicant has either:

1. A bachelors level college degree or equivalent in science, technology, business, statistics, mathematics, environmental policy, economics, or financial auditing; or
2. Evidence demonstrating the completion of significant and relevant work experience or other personal development activities that have provided the applicant with the communication, technical and analytical skills necessary to conduct verification.

(B) Evidence demonstrating sufficient workplace experience to act as a verifier, including evidence that the applicant has a minimum of two years of fulltime work experience in a professional role involved in emissions data management, emissions technology, emissions inventories, environmental auditing, or other technical skills necessary to conduct verification.

(4) The applicant must take an ARB approved general verification training course and receive a passing score of greater than an unweighted 70% on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the ARB approved general verification training course. Training under the previous version of the regulation does not qualify an applicant to retake an exam under this version without first taking the training class for this revised regulation.

(5) Sector Specific and Offset Project Specific Verifiers.

(A) The applicant seeking to be accredited as a sector specific verifier as specified in section 95131(a)(2) must, in addition to meeting the requirements for lead verifier or verifier qualification, have at least two years of professional experience related to the sector in which they are seeking accreditation, take ARB sector specific verification training and receive a passing score of greater than an unweighted 70% on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the ARB approved general verification training course.

(B) The applicant seeking to be accredited as an offset project specific verifier as specified in title 17, California Code of Regulations, section 95977(e)(4)(A)(iii), in addition to meeting the requirements for verifier qualification, shall meet the following requirements:

1. Be a verifier in good standing for the Climate Action Reserve prior to November 1, 2010 and have performed at least two project verifications for a project type by December 31, 2010; or
2. Have at least two years of professional experience related to developing emission inventories, conducting technical analyses, or environmental audits of the offset project type; and
3. Take ARB offset project verification training for an offset project type and receive a passing score of greater than an unweighted 70% on an exit examination. If the applicant does not pass the exam after the training, they may retake the exam a second time. Only one retake of the examination is allowed before the applicant is required to retake the ARB approved general verification training course.

(6) Nothing in this section shall be construed as preventing the Executive Officer from requesting additional information or documentation from an applicant after receipt of the application for accreditation as a verification body, lead verifier, or verifier, or from seeking additional information from other persons or entities regarding the applicant's fitness for qualification.

(c) *ARB Accreditation.*

(1) Within 90 days of receiving an application for accreditation as a verification body, lead verifier, or 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 verifier or lead verifier is complete and meets all applicable regulatory requirements, 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, 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, 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. The following requirements also apply at the time of application for re-accreditation as a lead verifier, verifier, sector specific verifier, or offset project verifier:

(A) If the applicant has not participated in at least one ARB verification by January 1, 2012, the applicant must take ARB approved GHG verification training that includes general verifier training and receive a passing score of greater than an unweighted 70% on the exit examination.

(B) If the applicant has participated in at least one ARB verification by January 1, 2012, then the applicant must take ARB approved abbreviated training that includes changes to the program since the original training was provided under 95132(b)(4), 95132(b)(5)(A), and 95132(b)(5)(B)3, and receive a passing score of greater than an unweighted 70% on the exit examination. This examination shall cover general verification and the training.

(5) All verification body requirements in section 95132(b)(1) must be met for the Executive Officer to renew the verification body accreditation.

(6) The Executive Officer and the applicant may mutually agree to longer time periods than those specified in subsections 95132(c)(1) or 95132(c)(3), and the applicant may submit additional supporting documentation before a decision has been made 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 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.

(8) Verifiers accredited by ARB prior to January 1, 2011 shall take ARB approved training to continue to provide verification services after January 1, 2012. The training will focus on changes to the program since the original training was provided under 95132(b)(4) and 95132(b)(5)(A). The verifier must receive a passing score of greater than an unweighted 70% on the exit examination.

(d) *Modification, Suspension, or Revocation of an Executive Order Approving a Verification Body, Lead Verifier, or Verifier.* The Executive Officer may review and, for good cause, including any violation of subarticle 4 of this article or any similar action in an analogous GHG system, modify, suspend, or revoke an Executive Order providing accreditation to a verification body, lead verifier, or verifier. The Executive Officer shall not revoke an Executive Order without affording the verification body, lead verifier, or verifier the opportunity for a hearing in accordance with the procedures specified in title 17, California Code of Regulations, section 60055.1 et seq.

(1) During suspension or revocation proceedings, the verification body, lead verifier, or verifier may not continue to provide verification services.

(2) Within 5 working days of suspension or revocation of accreditation, a verification body must notify all reporting entities, offset project operators, or authorized project designees for whom it is providing verification services, or has provided verification services within the past 6 months of its suspension or revocation of accreditation.

(3) A reporting entity, offset project operator, or authorized project designee who has been notified by a verification body of a suspended or revoked accreditation must contract with a new verification body for verification services.

(e) *Subcontracting.* The following requirements shall apply to any verification body that elects to subcontract a portion of verification services.

(1) All subcontractors must be accredited by ARB to perform the verification services for which the subcontractor has been engaged by the verification body.
(2) The verification body must assume full responsibility for verification services performed by subcontractor verifiers.
(3) A verification body shall not use subcontractors to meet the minimum staff total or lead verifier requirements as specified in section 95132(b)(1)(A)1. and section 95132(b)(1)(A)2.
(4) A verifier acting as a subcontractor to another verification body shall not further subcontract or outsource verification services for a reporting entity.
(5) A verification body that engages a subcontractor shall be responsible for demonstrating an acceptable level of conflict of interest, as provided in section 95133, between its subcontractor and the reporting entity for which it will provide verification services.
(6) A verification body may not use a subcontractor as the independent reviewer.

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

§ 95133. Conflict of Interest Requirements for Verification Bodies for Emissions Data Reports.

(a) The conflict of interest provisions of this section shall apply to verification bodies, lead verifiers, and verifiers accredited by ARB to perform verification services for reporting entities.

(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 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:

(A) Designing, developing, implementing, reviewing, or maintaining an inventory or information or data management system for facility air emissions, or, where applicable, electricity or fuel transactions, unless the review was part of providing greenhouse gas verification services;
(B) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis, including developing or reviewing a California Environmental Quality Act (CEQA) greenhouse gas analysis that includes facility specific information;
(C) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;
(D) Designing, developing, implementing, conducting an internal audit, consulting, or maintaining a GHG emissions reduction or GHG removal offset project as defined in the Cap-and-Trade Regulation;
(E) Owning, buying, selling, trading, or retiring shares, stocks, or emissions reduction credits from an offset project that was developed by or resulting reduction credits are owned by the reporting entity;
(F) Dealing in or being a promoter of credits on behalf of an offset project operator or authorized project designee where the credits are owned by or the offset project was developed by the reporting entity;
(G) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting entity;
(H) Appraisal services of carbon or greenhouse gas liabilities or assets;
(I) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;
(J) Directly managing any health, environment or safety functions for the reporting entity;
(K) Bookkeeping or other services related to accounting records or financial statements;
(L) Any service related to information systems, including ISO 14001 certification, unless those systems will not be part of the verification process;
(M) Appraisal and valuation services, both tangible and intangible;
(N) Fairness opinions and contribution-in-kind reports in which the verification body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services will not be part of the verification process;
(O) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;
(P) Any internal audit service that has been outsourced by the reporting entity or offset project operator that relates to the reporting entity's internal accounting controls, financial systems or financial statements, unless the result of those services will not be part of the verification process;
(Q) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the reporting entity;
(R) Any legal services;

(S) Expert services to the reporting entity or a legal representative for the purpose of advocating the reporting entity's interests in litigation or in a regulatory or administrative proceeding or investigation.

"Member" for the purposes of this section means any employee or subcontractor of the verification body or related entities of the verification body. "Member" also includes any individual with majority equity share in the verification body or its related entities. "Related entity" for the purposes of this section means any direct parent company, direct subsidiary, or sister company.

(3) The potential for conflict of interest shall be deemed to be high when any staff member of the verification body provides any type of non-monetary incentive to a reporting entity to secure a verification services contract.

(4) The potential for a conflict of interest shall also be deemed to be high where any staff member of the verification body has provided verification services for the reporting entity except within the time periods in which the reporting entity is allowed to use the same verification body as specified in sections 95130(a).

(c) The potential for a conflict of interest shall be deemed to be low where no potential for a conflict of interest is found under section 95133(b) and any non-verification services provided by any member of the verification body to the reporting entity within the last three years are valued at less than 20 percent of the fee for the proposed verification.

(d) The potential for a conflict of interest shall be deemed to be medium where the potential for a conflict of interest is not deemed to be either high or low as specified in sections 95133(b) and 95133(c). The potential for conflict of interest will also be deemed to be medium where there are any instances of personal or familial relationships between the members of the verification body and management or staff of the reporting entity.

(1) If a verification body identifies a medium potential for conflict of interest and intends to provide verification services for the reporting entity, the verification body shall submit, in addition to the submittal requirements specified in section 95133(e), a plan to avoid, neutralize, or mitigate the potential conflict of interest situation. At a minimum, the conflict of interest mitigation plan shall include:

(A) A demonstration that any individuals with potential conflicts have been removed and insulated from the project.

(B) An explanation of any changes to the organizational structure or verification body to remove the potential conflict of interest. A demonstration that any unit with potential conflicts has been divested or moved into an independent entity or any subcontractor with potential conflicts has been removed.

(C) Any other circumstance that specifically addresses other sources for potential conflict of interest.

(2) As provided in section 95133(f)(4), the Executive Officer shall evaluate the conflict of interest mitigation plan and determine whether verification services may proceed.

(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 body, its partners, 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 or any member of the verification team has previously provided verification services for the reporting entity and, if so, the years in which such verification services were provided;
(C) Identification of whether any member of the verification team or related entity has engaged in any non-verification services of any nature with the reporting entity either within or outside California during the previous three years. If non-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 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 or the accounting of greenhouse gas emissions or electricity or fuel transactions;
2. The nature of past, present or future relationships with the reporting entity including:

a. Instances when any member of the verification team has performed or intends to perform work for the reporting entity;
b. Identification of whether work is currently being performed for the reporting entity, and if so, the nature of the work;
c. How much work was performed for the reporting entity in the last three years, in dollars;

d. Whether any member of the verification team 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 years, in dollars.

3. Explanation of how the amount and nature of work previously performed is such that any member of the verification team's credibility and lack of bias should not be under question.

(D) A list of names of the staff that would perform verification services for the reporting entity, and a description of any instances of personal or family relationships with management or employees of the reporting entity that potentially represent a conflict of interest; and,

(E) Identification of any other circumstances known to the verification body, or reporting entity that could result in a conflict of interest.

(F) Attest, in writing, to ARB as follows:

"I certify under penalty of perjury of the laws of California the information provided in the Conflict of Interest submittal is true, accurate, and complete."

(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.

(1) The Executive Officer shall notify the verification body in writing when the conflict of interest evaluation information submitted under section 95132(e) is deemed complete. Within 30 working days of deeming the information complete, the Executive Officer shall determine whether the verification body is authorized to proceed with verification and must so notify the verification body.

(2) If the Executive Officer determines the verification body or any member of the verification team meets the criteria specified in section 95133(b), the Executive Officer shall find a high potential conflict of interest and verification services may not proceed.

(3) If the Executive Officer determines that there is a low potential conflict of interest, verification services may proceed.

(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 sections 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 and its subcontractors with the reporting entity, 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.*

(1) After commencement of verification services, the verification body shall monitor and immediately make full disclosure in writing to the Executive Officer regarding any potential for a conflict of interest situation that arises. This disclosure shall include a description of actions that the verification body has taken or proposes to take to avoid, neutralize, or mitigate the potential for a conflict of interest.

(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 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. 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.

(3) The verification body shall notify the Executive Office, within 30 days, of any emerging conflicts of interest during the time verification services are being provided.

(A) If the Executive Officer determines that a disclosed emerging potential conflict is medium risk and this risk can be mitigated, the verification body is deemed to have met the conflict of interest requirements to continue to provide verification services to the reporting entity and will not be subject to suspension or revocation of accreditation as specified in section 95132(d).

(B) If the Executive Officer determines that a disclosed emerging potential conflict is medium or high risk and this risk cannot be mitigated, the verification body will not be able to continue to provide verification services to the reporting entity, and may be subject to suspension or revocation of accreditation under section 95132(d).

(4) The verification body shall report to the Executive Officer any changes in its organizational structure, including mergers, acquisitions, or divestitures, for one year after completion of verification services.

(5) The Executive Officer may invalidate a verification finding if a potential conflict of interest has arisen for any member of the verification team. In such a case, the reporting entity shall be provided 90 days to complete re-verification.

(6) If the verification body or its subcontractor(s) are found to have violated the conflict of interest requirements of this article, the Executive Officer may rescind accreditation of the body, its verifier staff, or its subcontractor(s) as provided in section 95132(d).

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

(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 transfers such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures and storage tanks associated with the platform structure.

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production equipment means all structures associated with wells (including compressors, generators, or storage facilities), piping (including flowlines or intra-facility gathering lines), and portable non-self-propelled equipment (including 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 also includes associated storage or measurement and all systems engaged in gathering produced gas from multiple wells, all enhanced oil recovery (EOR) operations using CO_2 and thermal energy, and all petroleum and natural gas production located on islands, artificial islands or structures connected by a causeway to land, an island, or artificial island.

(3) *Onshore natural gas processing plants.* Natural gas processing plants are designed to separate and recover natural gas liquids (NGLs) or other non-methane gases and liquids from a stream of produced natural gas to meet onshore natural gas transmission pipeline quality specifications through equipment performing one or more of the following processes: oil and condensate removal, water removal, separation of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or other processes, and also the capture of CO_2 separated from natural gas streams for delivery outside the facility. In addition, field gathering and/or boosting stations that gather and process natural gas from multiple wellheads, and compress and transport natural gas (including flowlines or intra-facility gathering lines or compressors) as feed to the natural gas processing plants are considered a part of the processing plant. Gathering and boosting stations that send the natural gas to an onshore natural gas transmission compression facility, or natural gas distribution facility, or to an end user are considered stand alone natural gas processing facilities. All residue gas compression equipment operated by a processing plant, whether inside or outside the processing plant fence, are considered part of the natural gas processing plant.

(4) *Onshore natural gas transmission compression*. Onshore natural gas transmission compression means any fixed combination of compressors that move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, a transmission compressor station includes equipment for liquids separation, natural gas dehydration, and tanks for the storage of water and hydrocarbon liquids.

(5) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns utilized for storing natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement); and all the wellheads connected to the compression units located at the facility.

(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 re-gasification 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. 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 any location, including locations in the United States.

(8) *Natural Gas Distribution.* Natural gas distribution means distribution pipelines (not interstate pipelines or intrastate pipelines) and metering and regulating stations that physically deliver natural gas to end users.

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

§ 95151. Reporting Threshold and Reporting Entity.

(a) The operator of a facility in section 95150 who is required to report under section 95101 of this article, and who is not eligible for abbreviated reporting under section 95103(a), must comply with this subarticle in reporting GHG emissions from petroleum and natural gas systems to ARB.

(1) For the purposes of reporting for onshore petroleum and natural gas production, the operator is the operating entity listed on the state well drilling permit, or the state operating permit for wells where no drilling permit is issued by the state, who operates onshore petroleum and natural gas production wells and controls by means of ownership (including leased and rented) and operation (including contracted) stationary and portable equipment located on all well pads within a single hydrocarbon basin as defined by the American Association of Petroleum Geologists (AAPG) three-digit Geological Province Code (published 1991). Where more than one entity holds the state well drilling permit, or well operating permit where no well drilling permit is issued by the state, the permitted entities for the facility must designate one entity to report all emissions from the jointly controlled facility. Where an operating entity holds more than one permit to operate wells in a basin, then all onshore petroleum and natural gas production well permits in their name in the basin, including all equipment on well pads, would be considered one onshore petroleum and natural gas production facility for the purposes of reporting under this article.

(b) In determining whether a facility in section 95150 meets the reporting threshold defined in section 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.

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

§ 95152. GHGs to Report.

(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 (i) of this section, according to the requirements of sections 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 identified in the Minerals Management Service (MMS) Gulfwide Offshore Activity Data System (GOADS) study (2005 Gulfwide Emission Inventory Study MMS 2007-067).

(c) For onshore petroleum and natural gas production, the operator must report emissions from the following source types:

(1) Natural gas pneumatic high bleed device venting.
(2) Natural gas pneumatic low bleed device venting.
(3) Natural gas driven pneumatic pump venting.
(4) Well venting for liquids unloading.
(5) Gas well venting during conventional well completions.
(6) Gas well venting during unconventional well completions.
(7) Gas well venting during conventional well workovers.
(8) Gas well venting during unconventional well workovers.
(9) Gathering pipeline fugitives.
(10) Storage tanks.
(11) Reciprocating compressor rod packing venting.
(12) Well testing venting and flaring.
(13) Associated gas venting and flaring.
(14) Dehydrator vent stacks.
(15) Coal bed methane produced water emissions.
(16) EOR injection pump blowdown.
(17) Acid gas removal vent stacks.
(18) Centrifugal compressor wet seal degassing venting.
(19) Produced water dissolved CO_2.
(20) Fugitive emissions from valves, connectors, open ended lines, pressure relief valves, compressor starter gas vents, pumps, flanges, and other fugitive sources (such as instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and breather caps for crude services).

(d) For onshore natural gas processing, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor wet seal degassing venting.
(3) Storage tanks.
(4) Blowdown vent stacks.
(5) Dehydrator vent stacks.
(6) Acid gas removal vent stacks.
(7) Flare stacks.
(8) Gathering pipeline fugitives.
(9) Fugitive emissions from: valves, connectors, open ended lines, pressure relief valves, meters, and centrifugal compressor dry seals.

(e) For onshore natural gas transmission compression, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor wet seal degassing venting.
(3) Blowdown vent stacks.
(4) Natural gas pneumatic high bleed device venting.
(5) Natural gas pneumatic low bleed device venting.
(6) Fugitive emissions from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

(f) For underground natural gas storage, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor wet seal degassing venting.
(3) Natural gas pneumatic high bleed device venting.
(4) Natural gas pneumatic low bleed device venting.
(5) Fugitive emissions from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

(g) For LNG storage, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor wet seal degassing venting.
(3) Fugitive emissions from valves, pump seals, connectors, vapor recovery compressors, and other fugitive sources.

(h) For LNG import and export equipment, the operator must report emissions from the following sources:

(1) Reciprocating compressor rod packing venting.
(2) Centrifugal compressor wet seal degassing venting.
(3) Blowdown vent stacks.
(4) Fugitive emissions from valves, pump seals, connectors, vapor recovery compressors, and other fugitive sources.

(i) For natural gas distribution, the operator must report emissions from the following sources:

(1) Above ground meter regulators and gate station fugitive emissions from connectors, block valves, control valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.
(2) Below ground meter regulators and vault fugitives.
(3) Pipeline main fugitives.
(4) Service line fugitives.

(j) The operator must report the CO_2, CH_4, and N_2O emissions from each flare.

(k) The operator must report emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of section 95115 of this article.

(l) The operator must report CO_2 emissions captured and transferred off site by following the requirements of section 95123 of this article.

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

§ 95153. Calculating GHG Emissions.

(a) *Natural Gas Pneumatic High Bleed Device and Pneumatic Pump Venting.* The operator must calculate emissions from natural gas high bleed flow control device venting using the applicable method below:

(1) Method 1: The operator must calculate vented CH_4 and CO_2 emissions using manufacturer data. The operator may use this method through reporting year 2013 when metering of natural gas consumption in all high bleed devices and pneumatic pumps is required. By January 1, 2013 natural gas consumption must be metered for 50 percent of the operator's pneumatic high bleed devices and pneumatic pumps, and the operator must use Method 2 in section 95153(a)(3) for these metered devices and pumps. The operator may use Method 1 to calculate emissions from all unmetered devices and pumps in 2013. By January 1, 2014, the operator must meter natural gas consumption for all pneumatic high bleed devices and pneumatic pumps, and use Method 2 in section 95153(a)(3) to calculate emissions.

(2) The operator must calculate natural gas emissions for all unmetered high bleed devices and pneumatic pumps using the following equation:

$$E_{nm} = \sum_{d/p=1}^{n} B_{d/p} * T$$

Where:

E_{nm} = Annual natural gas emissions at standard conditions, in cubic feet for all pneumatic high bleed devices and pumps where natural gas consumption is not metered.

n = Total number of un-metered high bleed devices and pumps.

$B_{d/p}$ = Natural gas driven pneumatic device or pump emissions rate at standard conditions in cubic feet per minute, as provided by the manufacturer.

T = Amount of time in minutes that the pneumatic device or pump has been operational through the reporting period.

(3) Method 2: The operator must calculate vented emissions for all metered pneumatic high bleed devices and pneumatic pumps using the following equation:

$$E_m = \sum_{1}^{n} B_n$$

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.

(4) For both Method 1 and Method 2 of this paragraph, 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 the following equation:

$$E_{LB} = \sum_{LB=1}^{n} B_{LB} * T$$

Where:

E_{LB} = Annual natural gas emissions at standard conditions, in cubic feet for all pneumatic low bleed devices where natural gas consumption is not metered.

n = Total number of low bleed devices

B_{LB} = Natural gas driven low bleed pneumatic device emissions rate at standard conditions in cubic feet per minute, as provided by the manufacturer.

T = Amount of time in minutes that the pneumatic low bleed device has been operational during the reporting period.

(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.* For AGR (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), the operator must calculate emissions for CO_2 using the following equation:

$$E_{a,CO2} = (V_1 * \%Vol_1) - (V_2 * \%Vol_2)$$

Where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at ambient condition, in cubic feet per year.

V_1 = Metered total annual volume of natural gas flow into AGR unit in cubic feet per year at ambient condition.

$\%Vol_1$ = Volume weighted CO_2 content of natural gas into the AGR unit.

V_2 = Metered total annual volume of natural gas flow out of the AGR unit in cubic feet per year at ambient condition.

$\%Vol_2$ = Volume weighted CO_2 content of natural gas out of the AGR unit.

(1) If a continuous gas analyzer is installed, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, quarterly gas samples must be taken to determine $\%Vol_1$ and $\%Vol_2$ according to methods set forth in section 95154(a)(2) of this article.

(2) If AGR vent stack emissions are captured and re-injected into the oil/gas field, operators are exempt from reporting AGR vent stack emissions.

(3) The operator must calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(4) Mass CO_2 emissions must be calculated from volumetric CO_2 emissions using calculations in paragraphs (s) and (t) of this section.

(d) *Dehydrator Vent Stacks.* For dehydrator vent stacks without vapor recovery or thermal control devices, the operator must calculate annual mass CH_4 and CO_2 emissions at standard temperature and pressure (STP) conditions using the simulation software package GRI-GLYCalc Version 4.0 (published 2008).

(1) A minimum of the following parameters must be used for characterizing 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 natural gas.
(H) Use of flash tank separator (and disposition of recovered gas).
(I) Hours operated.
(J) Wet natural gas temperature, pressure, and composition.

(2) The operator must calculate annual emissions from dehydrator vent stacks to flares or regenerator fire-box/fire tubes as follows:

(A) The operator must use the dehydrator vent stack volume and gas composition as determined in paragraph (e)(1) of this section.

(B) The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine dehydrator vent stack emissions from the flare or regenerator combustion gas vent.

(3) Operators of dehydrators that use desiccant must calculate emissions from the amount of gas vented from the vessel every time it is depressurized for the desiccant refilling process using the following equation:

$$E_{s,n} = \sum_{1}^{n} \left(H * D^2 * \pi * P_2 * \%G\right) / \left(4 * P_1 * 1{,}000cf / Mcf\right)$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions (Mcf).
n = number of desiccant refillings during reporting period
H = Height of the dehydrator vessel (ft).
D = Inside diameter of the vessel (ft).
P_1 = Atmospheric pressure (psia) default = 14.7 psia.
P_2 = Pressure of the gas (psia).
π = pi (3.1416).
%G = Percent of packed vessel volume that is gas.

(A) 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*

(1) The operator must calculate emissions from each well venting for liquids unloading using the following equation:

$$E_{s,n} = \left\{\left(0.371 * 10^{-3}\right) * CD^2 * WD * SP * V\right\} + \left\{SFR * HR\right\}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.
$0.371 * 10^{-3}$ = {pi(3.1416)/4}/{(14.7*144) psia converted to pounds per square feet}
CD = Casing diameter (inches).
WD = Well depth (feet).
SP = Shut-in pressure (psig).
V = Number of vents per year.
SFR = Sales flow rate of gas well in cubic feet per hour immediately prior to the venting event.

HR = Hours that the well was left open to the atmosphere during unloading.

(2) 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.

(f) *Gas Well Venting During Unconventional Well Completions and Workovers*.

(1) The operator must calculate emissions from unconventional gas well venting during well completions and workovers from hydraulic fracturing using the following equation:

$$E_{a,n} = T * FR$$

Where:

$E_{a,n}$ = Annual natural gas vented emissions at ambient conditions in cubic feet.

T = Cumulative amount of time in hours of well venting during the year.

FR = Gas Flow Rate in cubic feet per hour, under ambient conditions, as required in paragraph (f)(1) of this section.

(2) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(3) 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.

(4) The flow rate for gas well venting during well completions and workovers from hydraulic fracturing must be determined using either of the calculation methodologies described in subparagraphs (A) and (B) below. The same calculation methodology must be used for the entire reporting year.

(A) Calculation Methodology 1. For one well completion in each gas producing field and for one well workover in each gas producing field, a recording flow meter must be installed on the vent line during each well unloading event according to methods set forth in section 95154(a)(2) of this article.

1. The average flow rate in cubic feet per minute of venting must be calculated for one well completion in each field and for one well workover in each field.
2. The respective flow rates must be applied to all well completions in the field and to all well workovers in the field, multiplied by the number of minutes of venting of all well completions and workovers, respectively, in that field.

3. New flow rates for completions and workovers must be calculated every other year for each reporting field and horizon.

(B) Calculation Methodology 2. For one well completion in each gas producing field and for one well workover in each gas producing field, the operator must record the pressures measured before and after the well choke according to methods set forth in section 95154(a)(2) of this article.

1. The average flow rate in cubic feet per minute of venting across the choke must be calculated for one well completion in each field and for one well workover in each field.
2. The respective flow rates must be applied to all well completions in the field and to all well workovers in the field, multiplied by the number of minutes of venting of all well completions and workovers in that field.
3. New flow rates for completions and workovers must be calculated every other year for each reporting field and horizon.

(C) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(D) 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) The operator must calculate annual emissions from gas well venting during well completions and workovers to flares as follows:

1. The operator must use the gas well venting volume during well completions and workovers as determined in paragraph (f)(4) of this section.
2. The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine gas well venting during well completions and workovers emissions from the flare.

(g) *Gas Well Venting During Conventional Well Completions and Workovers.* The operator must calculate emissions from each gas well venting during conventional well completions and workovers using the following equation:

$$E_{a,n} = \sum_{1}^{n} V * T$$

Where:

$E_{a,n}$ = Annual emissions in cubic feet at ambient conditions from gas well ventings during conventional well completions or workovers.

n = number of venting events per reporting period.

V = Daily gas production rate in cubic feet per minute immediately prior to venting event.

T = Cumulative amount of time of well venting in minutes during venting event.

(1) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
(2) 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.

(h) *Blowdown Vent Stacks.* The operator must calculate blowdown vent stack emissions as follows:

(1) The operator must calculate the total volume (including from pipelines, compressor case or cylinders, manifolds, suction and discharge bottles and vessels) between isolation valves.
(2) The operator must retain logs of the number of blowdowns for each equipment type according to the recordkeeping requirements of section 95105 of this article.
(3) The operator must calculate the total annual venting emissions using the following equation:

$$E_{a,n} = N * V_v$$

Where:
$E_{a,n}$ = Annual natural gas venting emissions at ambient conditions from blowdowns in cubic feet.
N = Number of blowdowns for the equipment in reporting year.
V_v = Total volume of blowdown equipment chambers (including pipelines, compressors and vessels) between isolation valves in cubic feet.

(4) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
(5) The operator must 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.

(i) *Onshore Production and Processing Storage Tanks.* For emissions from atmospheric pressure storage tanks receiving produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter) and onshore natural gas processing facilities, the operator must calculate annual CH_4 and CO_2 emissions using the appropriate method below. For storage tank batteries where the oil production rate is 10 barrels per day or less the operator must use Method 1. For storage tank batteries where the oil production rate is greater than 10 barrels per day the operator must use Method 2.

(1) Method 1: The operator must use this method for storage tank batteries where the oil production rate is 10 barrels per day or less. The operator must use E&P Tank Version 2.0 to calculate CH_4 and CO_2 emissions.

(A) A minimum of the following parameters must be used to characterize emissions from liquid transfer to atmospheric pressure storage tanks.

1. Separator oil composition.
2. Separator temperature.
3. Separator pressure.
4. Sales oil API gravity.
5. Sales oil production rate.
6. Sales oil Reid vapor pressure.
7. Ambient air temperature.
8. Ambient air pressure.

(B) The operator must determine if the storage tank has vapor recovery or thermal control devices.

1. The operator must adjust the emissions estimated using E&P Tank downward by the magnitude of emissions captured using a vapor recovery system for beneficial use.

(C) The operator must calculate emissions from liquids sent to atmospheric storage tanks vented to flares as follows:

1. The operator must use the storage tank emissions volume and gas composition as determined in this section.
2. The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine storage tank emissions from the flare.

(D) If liquids are sent to atmospheric storage tanks where the tank emissions are not represented by the equilibrium conditions of the liquid in a gas-liquid separator and calculated by E&P Tank, then emissions must be calculated as follows:

1. The operator must use the storage tank emissions as determined in this section.
2. The operator must multiply the emissions by 3.87 for sales oil less than 45 API gravity.
3. The operator must multiply the emissions by 5.37 for sales oil equal to or greater than 45 API gravity.

(2) Method 2: The operator must use the following method for storage tanks where the oil production rate is greater than 10 barrels per day.

(A) The operator must annually determine the Gas-Oil Ratio (GOR) of produced liquids (crude and condensate) for each storage tank. An additional sample must be collected, analyzed and emissions calculated when one or more producing wells are connected to or disconnected from the storage tank. Measurements are limited to land-based storage tanks containing condensate and crude oil.

1. A pressurized sample must be collected at a point downstream of all field separators, prior to the point where produced liquid is flashed to atmospheric pressure as it enters the storage tank. Sampling must be conducted under unbiased operating conditions.
2. A flash liberation test must be conducted and GOR and the mass fraction of CH_4 and CO_2 in the evolved gas determined.
   The following steps outline the flash liberation test:
   Step 1. The fluid sample is charged to a PVT cell.
   Step 2. The cell pressure is elevated to a pressure higher than saturation pressure by injecting mercury.
   Step 3. Pressure is lowered in small increments until the PVT cell is at atmospheric pressure.
   Step 4. The resulting volume of solution gas and oil remaining are measured and corrected to conditions of 60ºF and 14.65 psia.

3. Storage tanks equipped with a vapor recovery unit (VRU) or thermal oxidizer are exempt from reporting during periods when the destruction device is operational.

(B) The operator must determine CH_4 and CO_2 emissions using the following equation.

$$E_{CH4/CO2} = GOR * PR * MW_g / MVC * MF_{CH4/CO2} * 0.001$$

Where:

$E_{CH4/CO2}$ =	Methane or carbon dioxide emissions (metric tons/year).
GOR =	Gas-Oil Ratio (scf/bbl).
PR =	Oil production rate (bbl/measurement period).
MW_g =	Molecular weight of the gas (kg/kg-mole).
MVC =	Molar volume conversion factor.
$MF_{CH4/CO2}$ =	Mass fraction of CH_4 or CO_2 in gas (kg GHG/kg gas).
0.001=	Conversion factor.

(j) *Well Testing Venting and Flaring.* The operator must calculate well testing venting and flaring emissions as follows:

(1) The operator must collect a pressurized crude/condensate sample and determine the gas to oil ratio (GOR) of the hydrocarbon production from each well tested.
(2) The operator must estimate venting emissions using the following equation:

$$E_{a,n} = GOR * FR * D$$

Where:
$E_{a,n}$ = Annual volumetric natural gas emissions from well testing in cubic feet under ambient conditions.
GOR = Gas- Oil Ratio 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 well being tested.
D = Number of days during the year the well is tested.

(3) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
(4) The operator must 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.
(5) The operator must calculate emissions from well testing to flares as follows:

(A) The operator must use the well testing emissions volume and gas composition as determined in paragraphs (j)(1) through (3) of this section.
(B) The operator must 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.* The operator must calculate associated gas venting and flaring emissions as follows:

(1) The operator must collect a pressurized sample of crude/condensate and determine the GOR ratio of the hydrocarbon production from each well whose associated natural gas is vented or flared.
(2) The operator must estimate venting emissions using the following equation:

$$E_{a,n} = GOR * V$$

Where:
$E_{a,n}$ = Annual volumetric natural gas emissions from associated gas venting under ambient conditions, in cubic feet.
GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.
V = Total volume of oil produced in barrels in the reporting year.

(3) The operator must calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (r) of this section.

(4) The operator must 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.

(5) The operator must calculate emissions from associated natural gas to flares as follows:

(A) The operator must use the associated natural gas volume and gas composition as determined in paragraph (k)(1) through (3) of this section.

(B) The operator must use the calculation methodology of flare stacks in paragraph (l) of this section to determine associated gas emissions from the flare.

(l) *Flare Stacks.* The operator must calculate emissions from each flare stack as follows:

(1) If a continuous flow measurement device is installed on the flare, the operator must use the measured flow volumes to calculate the flare gas emissions. If a continuous flow measurement device is not installed on the flare, the operator can install a flow measuring device on the flare or use engineering calculations or company records to estimate volumetric flare gas flow.

(2) If a continuous gas composition analyzer is installed on gas to the flare, the operator must use these compositions in calculating emissions. If a continuous gas composition analyzer is not installed on gas to the flare, the operator can install a continuous gas composition analyzer on the flare or use the appropriate gas compositions for each stream of hydrocarbons going to the flare as specified in subparagraphs (A)-(B) below.

(A) When the stream going to flare is natural gas, the operator must use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead for onshore natural gas processing facilities.

(B) When the stream going to the flare is a hydrocarbon product stream, such as ethane or butane, then the operator must use a representative composition from the source for the stream.

(3) The operator must determine flare combustion efficiency from manufacturer supplied flare specifications. If not available, the operator must assume a flare combustion efficiency of 98 percent.

(4) The operator must determine CO_2, CH_4, and N_2O emissions resulting from the combustion of natural gas used as pilot gas according to the requirements of section 95115 of this article.

(5) For each unique gas stream destructed in the flare, the operator must calculate annual GHG volumetric emissions at actual conditions using the applicable equations below.

(A) The operator must calculate un-combusted flare stack methane emissions using the following equation:

$$E_{a,CH4} = V_a * (1 - \eta) * X_{CH4}$$

Where:

$E_{a,CH4}$ = Uncombusted methane emissions from the flare stack (scf).
V_a = Volume of gas sent to the flare (scf).
η = Flare destruction efficiency (expressed as a decimal, default = 0.98).
X_{CH4} = Concentration of methane in gas sent to the flare.

(B) The operator must calculate CO_2 combustion emissions for each unique gas stream sent flare using the following equation:

$$E_{CO2} = \eta * V * CC / MVC * 3.664 * 0.001$$

Where:

E_{CO2} = Combustion CO_2 emissions (MT of CO_2).
η = Flare destruction efficiency (expressed as a decimal, default = 0.98).
V = Volume of gas or liquid sent to the flare (scf).
CC = Carbon content of gas stream sent to the flare (kg C/kg-mole).
MVC = Molar volume conversion.
3.664 = Conversion factor (kg C to kg CO_2).
0.001 = Conversion factor (kg to metric tons).

1. The operator must calculate GHG volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
2. The operator must 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.
3. The operator must calculate N_2O emissions using the emission factors for Gas Flares listed in Table 8 of section 95158.
4. This emissions source excludes any emissions calculated under other emissions sources in section 95153 of this article.

(m) *Centrifugal Compressor Wet Seal Degassing Vents.* The operator must calculate CO_2 and CH_4 emissions from centrifugal compressor wet seal degassing vents as follows:

(1) For each centrifugal compressor, the operator must determine the volume of vapors from wet seal oil degassing tanks sent to an atmospheric vent or flare using a temporary or permanent flow measurement meter such as a vane anemometer according to methods set forth in section 95154(a)(2) of this article.

(2) The operator must estimate annual emissions using meter flow measurement using the following equation:

$$E_{a,i} = MT * T * M_i * (1 - B)$$

Where:

$E_{a,i}$ = Annual GHG i (i = either CH_4 or CO_2) volumetric emissions at ambient conditions.

MT = Average meter reading of gas emissions per unit time based on semi-annual measurements.

T = Total time the compressor associated with the wet seal(s) is operational in the reporting year.

M_i = Average mole percent of GHG i in the degassing vent gas based on semi-annual measurement; use the appropriate gas compositions in paragraph (s)(2) of this section.

B = Percentage of centrifugal compressor wet seal degassing vent gas sent to vapor recovery or fuel gas or other beneficial use as determined by keeping logs of the number of operating hours for the vapor recovery system and the amount of vent gas that is directed to the fuel gas system.

(3) The operator must calculate CH_4 and CO_2 volumetric emissions at standard conditions using paragraph (r) of this section.

(4) The operator must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (t) of this section.

(5) The operator must calculate emissions from degassing vent vapors to flares as follows:

(A) The operator must use the degassing vent vapor volume and gas composition as determined in paragraphs (m)(1) through (3) of this section.

(B) The operator must 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 Rod Packing Venting.* The operator must calculate annual CH_4 and CO_2 emissions from each reciprocating compressor rod packing venting for each applicable operational mode as follows:

(1) The operator must estimate annual emissions using a meter flow measurement using the following equation:

$$E_{a,i} = MT * T * M_i$$

Where:

$E_{a,i}$ = Annual GHG i (i = either CH_4 or CO_2) volumetric emissions at ambient conditions.

MT = Meter volumetric reading of gas emissions per unit time, under ambient conditions.

T = Total time the compressor associated with the venting is operational in the reporting year.

M_i = Mole percent of GHG i (i = either CO_2 or CH_4) in the vent gas; use the appropriate gas compositions in paragraph (s)(2) of this section.

(2) If the rod packing case is connected to an open ended vent line then the operator must use the following method to calculate emissions.

(A) The operator must measure volumetric emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown valves using bagging according to methods set forth in section 95154(a)(3) of this article.

(B) The operator must 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, unit isolation valves, and blowdown valves according to methods set forth in section 95154(a)(2).

(3) If the rod packing case is not equipped with a vent line, the operator must use the following method to estimate emissions:

(A) The operator must use the methods described in 95154(a) to conduct annual leak detection of fugitive emissions from the packing case into an open distance piece, or from the compressor crank case breather cap or vent with a closed distance piece.

(B) The operator must measure emissions using a high flow sampler, or calibrated bag, or appropriate meter according to methods set forth in section 95154(b) of this article.

(4) The operator must conduct one measurement for each compressor in each of the following operational modes that occurs during a reporting period:

(A) Operating.

(B) Standby, pressurized.

(C) Not operating, depressurized.

(5) The operator must calculate CH_4 and CO_2 volumetric emissions at standard conditions using calculations in paragraph (r) of this section.
(6) The operator must 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) of this article to conduct an annual leak detection of fugitive emissions from all sources listed in section 95152(d)(9), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1) of this article. This paragraph (o) applies to emissions sources in 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. If fugitive emissions are detected for sources listed in this paragraph, the operator must calculate emissions using the following equation for each source with fugitive emissions:

$$E_{s,i} = Count * EF * GHG_i * T$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each component fugitive source.

Count = Total number of this type of emission source found to be leaking.

EF = Leaker emission factor for specific sources listed in Tables 2 through 7 of section 95158.

GHG_i = Concentration of GHG i, (i = either CH_4 or CO_2), in the total hydrocarbon of the feed natural gas.

T = Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.

(1) The operator must calculate GHG mass emissions at standard conditions using the calculation in paragraph (t) of this section.
(2) Operators of onshore natural gas processing facilities must use the appropriate default leaker emission factors listed in Table 2 of section 95158 for fugitive emissions detected from valves, connectors, open ended lines, pressure relief valves, meters, and centrifugal compressor dry seals.
(3) Operators of onshore natural gas transmission compression facilities must use the appropriate default leaker emission factors listed in Table 3 of section 95158 for fugitive emissions detected from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters regulators, and open ended lines.
(4) Operators of underground natural gas storage facilities for storage stations must use the appropriate default leaker emission factors listed in Table 4 of section 95158 for fugitive emissions detected from connectors, block valves, control valves, compressor blowdown valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

(5) Operators of LNG storage facilities must use the appropriate default leaker emission factors listed in Table 5 of section 95158 for fugitive emissions detected from valves, pump seals, connectors, and other.

(6) Operators of LNG import and export facilities must use the appropriate default leaker emission factors listed in Table 6 of section 95158 for fugitive emissions detected from valves, pump seals, connectors, and other.

(7) Operators of natural gas distribution facilities for above ground meter regulator and gate stations must use the appropriate default leaker emission factors listed in Table 7 of section 95158 for fugitive emissions detected from connectors, block valves, control valves, pressure relief valves, orifice meters, other meters, regulators, and open ended lines.

(p) *Population Count and Emission Factors.* This paragraph applies to emissions sources listed in section 95152(c)(2), (c)(9), (c)(15), (c)(21), (d)(8), (e)(6), (f)(4), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3) and (i)(4), of this article 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. Operators must calculate emissions from all sources listed in this paragraph using the following equation:

$$E_{s,i} = Count * EF * GHG_i * T$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each fugitive source.

Count = Total number of this type of emission source at the facility.

EF = Population emission factor for specific sources listed in Tables 1 through 7 of section 95158.

GHG_i = Concentration of GHG i, (i = either CH_4 or CO_2), in produced natural gas or feed natural gas.

T = Total time the specific source associated with the fugitive emission was operational in the reporting year, in hours.

(1) Operators must calculate both CH_4 and CO_2 mass emissions from volumetric emissions using the calculation in paragraph (t) of this section.

(2) Operators of onshore petroleum and natural gas production facilities must use the appropriate default population emission factors listed in Table 1 of section 95158 for fugitive emissions from valves, connectors, open ended lines, pressure relief valves, compressor starter gas vent, pump, flanges, other, and CBM well water production. Where facilities conduct EOR operations, the emissions factor listed in Table 1 of section 95158 must be used to estimate all stream of gases, including recycle CO_2 stream. In cases where the stream is almost all CO_2, the emissions factors in Table 1 of section 95158 must be assumed to be for CO_2 instead of natural gas.

(3) Operators of onshore natural gas processing facilities must use the appropriate default population emission factor listed in Table 2 of section 95158 for fugitive emission from gathering pipelines.

(4) Operators of underground natural gas storage facilities for storage wellheads must use the appropriate default population emission factors listed in Table 4 of section 95158 for fugitive emissions from connectors, valves, pressure relief valves, and open ended lines.

(5) Operators of LNG storage facilities must use the appropriate default population emission factors listed in Table 5 of section 95158 for fugitive emissions from vapor recovery compressors.

(6) Operators of LNG import and export facilities must use the appropriate default population emission factor listed in Table 6 of section 95158 for fugitive emissions from vapor recovery compressors.

(7) Operators of natural gas distribution facilities must use the appropriate default population emission factors listed in Table 7 of section 95158 for fugitive emissions from below grade metering & regulating (M&R) stations, gathering pipelines, mains, and services.

(q) *Offshore Petroleum and Natural Gas Production Facilities*. Operators must report GHG emissions from all "stationary fugitive" and "stationary vented" sources as identified in the Minerals Management Service (MMS) Gulfwide Offshore Activity Data System (GOADS) study (2005 Gulfwide Emission Inventory Study MMS 2007-067) for each platform. Operators of offshore production facilities who had not previously reported under the MMS GOADS program must collect monthly activity data from platform sources for the first reporting year in accordance with the MMS GOADS program instructions. Annual emissions must be calculated using the MMS GOADS emission factors and methods.

(1) In subsequent reporting years, facilities not reporting under GOADS must follow the same data collection cycle as GOADS in collecting new activity data monthly to estimate emissions and report emissions.

(2) For each reporting year that does not overlap with the GOADS reporting year, operators must report the last reported emissions data with emissions adjusted based on the operating time for each platform.

(3) If MMS discontinues or delays their GOADS survey by more than 4 years, then platform operators must collect monthly activity data every 4 years from platform sources in accordance with the MMS GOADS program instructions, and annual emissions must be calculated using the MMS GOADS emission factors and methods.

(r) *Volumetric Emissions.* Operators must calculate volumetric emissions at standard conditions as specified in paragraphs (r)(1) or (2) of this section.

(1) Operators must calculate natural gas volumetric emissions at standard conditions by converting ambient temperature and pressure of natural gas emissions to standard temperature and pressure natural gas using the following equation:

$$E_{s,n} = E_{a,n} * (460 + T_s) * P_a / (460 + T_a) * P_s$$

Where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions.
$E_{a,n}$ = Natural gas volumetric emissions at ambient conditions.
T_s = Temperature at standard conditions (°F).
T_a = Temperature at actual emission conditions (°F).
P_s = Absolute pressure at standard conditions (inches of Hg).
P_a = Absolute pressure at ambient conditions (inches of Hg).

(2) Calculate GHG volumetric emissions at standard conditions by converting ambient temperature and pressure of GHG emissions to standard temperature and pressure using the following equation:

$$E_{s,i} = E_{a,i} * (460 + T_s) * P_a / (460 + T_a) * P_s$$

Where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions.
$E_{a,i}$ = GHG i volumetric emissions at actual conditions.
T_s = Temperature at standard conditions (°F).
T_a = Temperature at actual emission conditions (°F).
P_s = Absolute pressure at standard conditions (inches of Hg).
P_a = Absolute pressure at ambient conditions (inches of Hg).

(s) *GHG Volumetric Emissions.*

(1) Operators must estimate CH_4 and CO_2 emissions from natural gas emissions using the following equation:

$$E_{s,i} = E_{s,n} * M_i$$

Where:

$E_{s,i}$ = GHG i (i = either CH_4 or CO_2) volumetric emissions at standard conditions.
$E_{s,n}$ = Natural gas volumetric emissions at standard conditions.
M_i = Mole percent of GHG i (i = CH_4 or CO_2) in the natural gas.

(2) For the equation in paragraph (s)(1), the mole percent, M_i, must be the annual average mole percent for each facility, as specified in paragraphs (s)(2)(A) through (G) of this section.

(A) GHG mole percent in produced natural gas for onshore petroleum and natural gas production facilities. If operators have a continuous gas composition analyzer installed for produced natural gas, the operator must use these values in calculating emissions. If the operator does not have a continuous gas composition analyzer installed, then quarterly samples must be taken according to methods set forth in section 95154(a)(2) of this article.

(B) GHG mole percent in feed natural gas for all emissions sources upstream of the de-methanizer and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead for onshore natural gas processing facilities. If the operator has a continuous gas composition analyzer on feed natural gas, the operator must use these values in calculating emissions. If the operator does not have a continuous gas composition analyzer, then quarterly samples must be taken according to methods set forth in section 95154(a)(2) of this article.

(C) GHG mole percent in transmission pipeline natural gas that passes through the facility for onshore natural gas transmission compression facilities.

(D) GHG mole percent in natural gas stored in underground natural gas storage facilities.

(E) GHG mole percent in natural gas stored in LNG storage facilities.

(F) GHG mole percent in natural gas stored in LNG import and export facilities.

(G) GHG mole percent in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities.

(t) *GHG Mass Emissions.* The operator must calculate GHG mass emissions at standard conditions by converting the GHG volumetric emissions into mass emissions using the following equation:

$$Mass_{s,i} = E_{s,i} * \rho_i * 10^{-3}$$

Where:

$Mass_{s,i}$ = GHG i (either CH_4 or CO_2) mass emissions at standard conditions in metric tons.

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

ρ_i = Density of GHG i, 0.053 kg/ft^3 for CO_2 and 0.0193 kg/ft^3 for CH_4.

(u) *EOR Injection Pump Blowdown.* The operator must calculate pump blowdown emissions as follows:

(1) The operator must calculate the total volume in cubic feet (including from pipelines, compressors and vessels) between isolation valves.

(2) The operator must retain logs of the number of blowdowns per reporting period according to the recordkeeping requirements of section 95105 of this article.

(3) The operator must calculate the total annual venting emissions using the following equation:

$$Mass_{c,i} = N * V_v * R_c * GHG_i * 10^{-3}$$

Where:

$Mass_{c,i}$ = Annual EOR injection gas venting emissions in metric tons at critical conditions "c" from blowdowns.

N = Number of blowdowns for the equipment in reporting year.

V_v = Total volume in cubic feet of blowdown equipment chambers (including pipelines, compressors, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft^3.

GHG_i = Mass fraction of GHG_i in critical phase injection gas.

(v) *Produced Water Dissolved CO_2.* The operator must calculate dissolved CO_2 in produced water as follows:

(1) The operator must determine the amount of CO_2 retained in produced water at STP conditions. Quarterly samples must be taken according to methods set forth in section 95154(a)(2) of this article to determine retention of CO_2 in produced water immediately downstream of the separator where hydrocarbon liquids and produced water are separated. The operator must use the average of the quarterly analysis for the reporting period.

(2) The operator must estimate emissions using the following equation:

$$Mass_{s,CO2} * S_{pw} * V_{pw}$$

Where:

$Mass_{s,CO2}$ = Annual CO_2 emissions from CO_2 retained in produced water beyond tankage, in metric tons.

S_{pw} = Amount of CO_2 retained in produced water in metric tons per barrel, under standard conditions.

V_{pw} = Total volume of produced water produced in barrels in the reporting year.

(3) EOR operations that route produced water from separation directly to re-injection into the hydrocarbon reservoir in a closed loop system without any leakage to the atmosphere are exempt from paragraph (v) of this section.

(w) *Portable Equipment Combustion Emissions.* The operator must calculate emissions from portable equipment pursuant to section 95115 of this article.

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

§ 95154. Monitoring and QA/QC Requirements.

(a) The operator must use the method described as follows to conduct annual leak detection of fugitive emissions from all source types listed in section 95153(n)(3)(A) and 95153(o) of this article in operation or on standby mode that occur during a reporting period.

(1) Optical gas imaging instrument. The operator must use an optical gas imaging instrument for fugitive emissions detection in accordance with 40 CFR part 60, subpart A, §60.18(i)(1) and (2), Alternative Work Practice for Monitoring Equipment Leaks (revised as of July 1, 2009). In addition, the operator must operate the optical gas imaging instrument to image the source types required by this article in accordance with the instrument manufacturer's operating parameters.

(2) All flow meters, composition analyzers and pressure gauges that are used to provide data for the GHG emissions calculations must use measurement methods, maintenance practices, and calibration methods that are consistent with the requirements of section 95103(k).

(3) The operator must use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures such that it is safe to handle and capture all the emissions, below the maximum temperature specified by the vent bag manufacturer, and the entire emissions volume can be encompassed for measurement.

(A) The operator must 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.

(B) The operator must perform three measurements of the time required to fill the bag and report the emissions as the average of the three readings.

(C) The operator must estimate natural gas volumetric emissions at standard conditions using the calculations in section 95153(r) of this article.

(D) The operator must estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in section 95153(s) and (t) of this article.

(b) The operator must use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions must conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the fugitive emissions 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 the operator must use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) The operator must estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in section 95153(s) and (t) of this article.

(4) The operator must calibrate the instrument at 2.5 percent CH_4 with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following the manufacturer's instructions for calibration.

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

(1) To substitute for missing data for emissions reported under section 95115 of this article (stationary combustion units and units using continuous emissions monitoring systems), the operator must follow the requirements of section 95129 of this article.

(2) If data required by this subarticle are missing and additional sampling and/or analysis is not possible, the operator must generate a substitute value as follows:

(A) If the analytical data capture rate is at least 90 percent for the data year, the operator must substitute each missing value using available process data.

(B) If the analytical data capture rate is at least 80 percent but not at least 90 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter during the given data year, as well as the two previous data years.

(C) If the analytical data capture rate is less than 80 percent for the data year, the operator must substitute each missing value with the highest quality assured value recorded for the parameter in all records kept according to section 95105(a).

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

§ 95156. Data Reporting Requirements.

In addition to the information required by 40 CFR §98.3(c), each annual report must contain reported emissions as specified in this section.

(a) The operator must report annual emissions separately for each of the industry segments listed in paragraphs (a)(1) through (a)(8) of this section. For each segment, the operator must report emissions from each source type in the aggregate, unless specified otherwise. For example, the operator of an underground natural gas storage operation with multiple reciprocating compressors must report emissions from all reciprocating compressors as an aggregate number.

(1) Onshore petroleum and natural gas production.

(A) Petroleum and natural gas produced using thermal EOR.
(B) Petroleum and natural gas produced using production methods other than thermal EOR.

(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. The operator must report each source in the aggregate for pipelines and for Metering and Regulating (M&R) stations.

(b) The operator must report emissions separately for standby equipment.

(c) The operator must report activity data for each aggregated source type as follows:

(1) Count of natural gas pneumatic high bleed devices.
(2) Count of natural gas pneumatic low bleed devices.
(3) Count of natural gas driven pneumatic pumps.
(4) For each acid gas removal unit the operator must report the following:

(A) Total volume of natural gas flow into the acid gas removal unit.
(B) Total volume of natural gas flow out of the acid gas removal unit.
(C) Volume weighted CO_2 content of natural gas into the acid gas removal unit.

(5) For each dehydrator unit the operator must report the following:

(A) Glycol dehydrators:

1. Glycol dehydrator feed natural gas flow rate.
2. Glycol dehydrator absorbent circulation pump type.
3. Glycol dehydrator absorbent circulation rate.
4. Whether stripper gas is used in glycol dehydrator.
5. Whether a flash tank separator is used in glycol dehydrator.

(B) Desiccant dehydrators:

1. The number of desiccant dehydrators operated.

(6) Count of wells vented to the atmosphere for liquids unloading for each field in the basin.

(7) Count of wells venting during well completions for each field in the basin.

(A) Number of conventional completions.
(B) Number of completions involving hydraulic fracturing.

(8) Count of wells venting during well workovers for each field in the basin.

(A) Number of conventional well workovers involving well venting to the atmosphere.
(B) Number of unconventional well workovers involving well venting to the atmosphere.

(9) For each compressor blowdown vent stack the operator must report the following for each compressor:

(A) Type of compressor whether reciprocating or centrifugal.
(B) Compressor capacity in horse powers.
(C) Volume of gas between isolation valves.
(D) Number of blowdowns per year.

(10) For each estimate of gas emitted from liquids sent to atmospheric tank using E&P Tank, the operator must report the following:

(A) Immediate upstream separator temperature and pressure.
(B) Sales oil API gravity.
(C) Estimate of individual tank or tank battery capacity in barrels.
(D) Oil, hydrocarbon condensate and water sent to tank(s) in barrels.
(E) Control measure: either vapor recovery system or flaring of tank vapors.

(11) For tank emissions identified using optical gas imaging instrument per section 95154(a) of this article, the operator must report the following for each tank:

(A) Immediate upstream separator temperature and pressure.
(B) Sales oil API gravity.
(C) Tank capacity in barrels.
(D) Tank throughput in barrels.
(E) Control measure: either vapor recovery system or flaring of tank vapors.
(F) Optical gas imagining instrument used.
(G) Meter used for measuring emissions.
(H) List of emissions sources routed to the tank.

(12) For well testing, the operator must report the following for each field in the basin:

(A) Number of wells tested in reporting period.
(B) Average gas to oil ratio for each field.
(C) Average flow rate during testing for each field.
(D) Average number of days the well is tested.
(E) Whether the hydrocarbons produced during testing are vented or flared.

(13) For associated natural gas venting, the operator must report the following for each field in the basin:

(A) Number of wells venting or flaring associated natural gas in reporting period.
(B) Average gas to oil ratio for each field.
(C) Average volume of oil produced per well per field.
(D) Whether the associated natural gas is vented or flared.

(14) For flare stacks, the operator must report the following for each flare:

(A) Whether the flare has a continuous flow monitor.
(B) If using engineering estimation methods, identify sources of emissions going to the flare.
(C) Whether the flare has a continuous gas analyzer.
(D) Identify the proportion of total natural gas to pure hydrocarbon stream being sent to the flare annually for the reporting period.
(E) Flare combustion efficiency.

(15) For well venting for liquids unloading, the operator must report the following by field, basin, and well tubing size:

(A) Number of wells being unloaded for liquids in reporting year.
(B) Average number of unloading(s) per well per reporting year.
(C) Average volume of natural gas produced per well per reporting year during liquids unloading.

(16) For well completions and workovers, the operator must report the following for each field in the basin:

(A) Number of wells completed (worked over) in reporting year.
(B) Average number of days required for completion (workover).
(C) Average volume of natural gas produced per well per reporting year during well completion (workover).

(17) For compressor wet seal degassing vents, the operator must report the following for each degassing vent:

(A) Number of wet seals connected to the degassing vent.
(B) Number of compressors whose wet seals are connected to the degassing vent.
(C) Total throughput of compressors whose wet seals are connected to the degassing vent.
(D) Type of meter used for making measurements.
(E) Whether emissions estimate is based on a continuous or one time measurement.
(F) Total time the compressor(s) associated with the degassing vent stack is operating. Sum the hours of operation if multiple compressors are connected to the vent stack.
(G) Proportion of vent gas recovered for fuel gas or sent to a flare.

(18) For reciprocating compressor rod packing, the operator must report the following per rod packing:

(A) Total throughput of the reciprocating compressor whose rod packing emissions is being reported.
(B) Total time in hours the reciprocating compressor is in operating mode.
(C) Whether or not the rod packing case is connected to an open ended line.
(D) If rod packing is connected to an open ended line, report type of device used for measurement of emissions.
(E) If rod packing is not connected to an open ended vent line, report the locations from where the emissions from the rod packing are detected.

(19) For fugitive emissions sources using emission factors for estimating emissions, the operator must report the following:

(A) Component count for each fugitive emissions source.
(B) CH_4 and CO_2 in produced natural gas for onshore petroleum and natural gas production.

(20) For EOR injection pump blowdown, the operator must report the following per pump:

(A) Pump capacity.
(B) Volume of gas between isolation valves.
(C) Number of blowdowns per year.
(D) Supercritical phase EOR injection gas density.

(21) For hydrocarbon liquids dissolved CO_2, the operator must report the following for each field in the basin:

(A) Volume of crude oil produced.

(22) For produced water dissolved CO_2 the operator must report the following for each field in the basin:

(A) Volume of produced water produced.

(d) Minimum, maximum and average throughput for each operation listed in paragraphs (a)(1) through (a)(8) of this section.

(e) For offshore petroleum and natural gas production facilities, the number of connected wells, and whether the wells are producing oil, gas, or both.

(f) The operator must report emissions separately for portable equipment for the following source types: drilling rigs, dehydrators, compressors, electrical generators, steam boilers, and heaters.

(1) Aggregate emissions by source type.
(2) Report count of each source type.

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

§ 95157. Records That Must be Retained.

In addition to the information required by 40 CFR §98.3(g), the operator must retain the following records according to the recordkeeping requirements of section 95105 of this article:

(a) Dates on which measurements were conducted.

(b) Results of all emissions detected and measurements.

(c) Calibration reports for detection and measurement instruments used.

(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.

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

§ 95158. Default Emission Factor Tables.

Table 1. Default Whole Gas Emission Factors for Onshore Production

Onshore production		*Emission Factor (scf/hour/ component)*
Population Emission Factors--All Components, Gas Service		
	Valve	0.08
	Connector.	0.01
	Open-ended Line	0.04
	Pressure Relief Valve	0.17
	Low-Bleed Pneumatic Device Vents	2.75
	Gathering Pipelines[1]	2.81
	CBM Well Water Production[2]	0.11
Population Emission Factors--All Components, Light Crude Service[3]		
	Valve	0.04
	Connector.	0.01
	Open-ended Line	0.04
	Pump	0.01
	Other[5]	0.24
Population Emission Factors--All Components, Heavy Crude Service[4]		
	Valve	0.04
	Connector	0.01
	Open-ended Line	0.04
	Pump	0.01
	Other[5]	0.24
	Valve	0.001
	Flange	0.001
	Connector (other)	0.0004
	Open-ended Line	0.01
	Other[5]	0.003

[1] Emission Factor is in units of ”scf/hour/mile.”
[2] Emission Factor is in units of “scf methane/gallon,” in this case the operating factor is ”gallons/year” and do not multiply by methane content.
[3] Hydrocarbon liquids greater than or equal to 20*API are considered “light crude.”
[4] Hydrocarbon liquids less than 20*API are considered “heavy crude.”
[5] ”Others” category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.

Table 2. Default Total Hydrocarbon Emission Factors for Processing

Processing		*Before de-methanizer emission factor (scf/hour/ component)*	*After de-methanizer Emission factor (scf/hour/ component)*
Leaker Emission Factors--Reciprocating Compressor Components, Gas Service			
	Valve	15.88	18.09
	Connector.	4.31	9.10
	Open-ended Line	17.90	10.29
	Pressure Relief Valve	2.01	30.46
	Meter	0.02	48.29
Leaker Emission Factors--Centrifugal Compressor Components, Gas Service			
	Valve	0.67	2.51
	Connector.	2.33	3.14
	Open-ended Line	17.90	16.17
	Dry Seal	105	105
Leaker Emission Factors--Other Components, Gas Service			
	Valve		6.42
	Connector		5.71
	Open-ended Line		11.27
	Pressure Relief Valve		2.01
	Meter		2.93
Population Emission Factors--Other Components, Gas Service			
	Gathering Pipelines[1]		2.81

[1] Emission Factor is in units of “scf/hour/mile.”

Table 3. Default Methane Emission Factors for Transmission

Transmission		*Emission Factor (scf/hour/ component)*
Leaker Emission Factors--All Components, Gas Service		
	Connector	2.7
	Block Valve	10.4
	Control Valve	3.4
	Compressor Blowdown Valve	543.5
	Pressure Relief Valve	37.2
	Orifice Meter	14.3
	Other Meter	0.1
	Regulator	9.8
	Open-ended Line	21.5
Population Emission Factors--Other Components, Gas Service		
	Low-Bleed Pneumatic Device Vents	2.57

Table 4. Default Methane Emission Factors for Underground Storage

Underground Storage		*Emission Factor (scf/hour/ component)*
Leaker Emission Factors--Storage Station, Gas Service		
	Connector	0.96
	Block Valve	2.02
	Control Valve	3.94
	Compressor Blowdown Valve	66.15
	Pressure Relief Valve	19.80
	Orifice Meter	0.46
	Other Meter	0.01
	Regulator	1.03
	Open-ended Line	6.01
Population Emission Factors--Storage Wellheads, Gas Service		
	Connector	0.01
	Valve	0.10
	Pressure Relief Valve	0.17
	Open-ended Line	0.03
Population Emission Factors--Other Components, Gas Service		
	Low-Bleed Pneumatic Device Vents	2.57

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, LNG 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	6.81

[1] "Other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.

Table 6. Default Methane Emission Factors for LNG Terminals

LNG Terminals		*Emission Factor (scf/hour/ component)*
Leaker Emission Factors--LNG Storage Components, LNG Service		
	Valve	1.19
	Pump Seal	4.00
	Connector	0.34
	Other	1.77
Population Emission Factors-- LNG Terminals Compressor, Gas Service		
	Vapor Recovery Compressor	6.81

Table 7. Default Methane Emission Factors for Distribution

Distribution		Emission Factor (scf/hour/ component)
Leaker Emission Factors--Above Grade M&R Stations Components, Gas Service		
	Connector	1.69
	Block Valve	0.557
	Control Valve	9.34
	Pressure Relief Valve	0.270
	Orifice Meter	0.212
	Regulator	0.772
	Open-ended Line	26.131
Population Emission Factors--Below Grade M&R Stations Components, Gas Service[1]		
	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[2]		
	Unprotected Steel	12.58
	Protected Steel	0.35
	Plastic	1.13
	Copper	27.25
Population Emission Factors--Distribution Services, Gas Service[2]		
	Unprotected Steel	0.19
	Protected Steel	0.02
	Plastic	0.001
	Copper	0.03

[1] Emission Factor is in units of “scf/hour/station.”
[2] Emission Factor is in units of “scf/hour/service.”

Table 8. Default Nitrous Oxide Emission Factors for Gas Flaring

		Emission Factor (metric tons/MMscfgas production or receipts)
Population Emission Factors--Gas Flaring		
	Gas Production	5.90E-07
	Sweet Gas Processing	7.10E-07
	Sour Gas Processing	1.50E-06
	Conventional Oil Production[1]	1.00E-04
	Heavy Oil Production[2]	7.30E-05

[1] Emission Factor is in units of “metric tons/barrel conventional oil production.”
[2] Emission Factor is in units of ”metric tons/barrel heavy oil production.”

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