REGULATION FOR THE MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

Adopt new Subchapter 10, Article 2, sections 95100 to 95133, title 17, California Code of Regulations, to read as follows:

Subchapter 10: Climate Change

This subchapter contains regulations to implement the California Global Warming Solutions Act of 2006 (Stats. 2006; Chapter 488; Health and Safety Code sections 38500 et seq.)

Article 1: [Reserved]

Article 2: Mandatory Greenhouse Gas Emissions Reporting

§ 95100. Purpose.

The purpose of this article is to require the reporting and verification of greenhouse gas emissions from specified greenhouse gas emissions sources. This article is designed to meet the requirements of section 38530 of the Health and Safety Code.

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

§ 95101. Applicability.

(a) ***Organization of this Article.*** Subarticle 1 specifies general requirements for the reporting of greenhouse gas emissions that apply to all facilities listed below in section (b). Subarticle 2 specifies reporting requirements and calculation methods for specific types of facilities. Subarticle 3 specifies calculation methods that are applicable to multiple types of facilities. Subarticle 4 specifies greenhouse gas emissions data report verification requirements and the requirements for those who perform greenhouse gas emission verifications.

(b) Except as provided in section 95101(c) and section 95103(e), this article applies to the following entities:

    (1)   Operators of cement plants in California;
    (2)   Operators of petroleum refineries in California that emit greater than or equal to 25,000 metric tonnes of CO_2 in any calendar year after 2007 from the combination of stationary combustion and process sources;

(3) Operators of hydrogen plants in California that emit greater than or equal to 25,000 metric tonnes of CO_2 in any calendar year after 2007 from the combination of stationary combustion sources and hydrogen production processes;

(4) Operators of electricity generating facilities that are located in California or operated by a retail provider as defined in section 95102(a), that individually have a nameplate generating capacity greater than or equal to 1 megawatt (MW), and that emit greater than or equal to 2,500 metric tonnes of CO_2 in any calendar year after 2007 from electricity generating activities, including hybrid generating facilities;

(5) Retail providers as defined in section 95102(a);

(6) Marketers as defined in section 95102(a);

(7) Operators of cogeneration facilities that are located in California or operated by a retail provider as defined in section 95102(a) that individually have a nameplate generating capacity greater than or equal to 1 megawatt (MW), and that emit greater than or equal to 2,500 metric tonnes of CO_2 in any calendar year after 2007 from electricity generating activities;

(8) Operators of other facilities in California that emit greater than or equal to 25,000 metric tonnes per year of CO_2 from stationary combustion sources in any calendar year after 2007.

(c) 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;

(2) Portable equipment;

(3) Generating units designated as backup or emergency generators in a permit issued by an air pollution control district or air quality management district;

(4) Hospitals with a North American Industry Classification System (NAICS) code starting with 62;

(5) Primary and secondary schools with a NAICS code of 611110.

(d) The Executive Officer may request a demonstration from any entity operating a facility to establish that a specified facility does not meet one or more of the applicability criteria specified in section 95101(b). Such demonstration shall be provided to the Executive Officer within 20 working days of a written request received from the Executive Officer.

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

Subarticle 1. General Requirements for the Mandatory Reporting of Greenhouse Gas Emissions

§ 95102.   Definitions.

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

(1) "Accuracy" means the closeness of the agreement between the result of the measurement and the true value of the particular quantity (or a reference value determined empirically using internationally accepted and traceable calibration materials and standard methods), taking into account both random and systematic factors.

(2) "Adverse verification opinion" means a verification opinion rendered by a verification body stating that the verification body cannot say with reasonable assurance that the submitted emissions data report is free of material misstatement, or that it cannot provide a qualifying statement that the emissions data report conforms to the requirements of this article.

(3) "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.

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

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

(6) "Asphalt" means a dark brown or black cementitious material (solid or liquid) of which the main constituents are bitumins that occur naturally or as a residue of petroleum refining.

(7) "Asphalt blowing" means the process by which air is blown through asphalt flux to change the softening point and penetration rate.

(8) "Asset controlling supplier" means any entity that operates electricity generating facilities or serves as an exclusive marketer for certain generating facilities even though it does not own them.

(9) "Asset owning supplier" means any entity owning electricity generating facilities that delivers electricity to a transmission or distribution line.

(10) "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.

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

(12) "Best available data and methods" means ARB methods for emissions calculations set forth in this article where reasonably feasible; or facility fuel use and other facility process data used in conjunction with ARB provided emission factors and other data; or other generally accepted methods for calculating greenhouse gas emissions.

(13) "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.

(14) "Biomass-derived fuels" or "biomass fuels" means fuels derived entirely from biomass.

(15) "Bottom ash" means ash that collects at the bottom of a combustion chamber.

(16) "Bottoming cycle plant" means a cogeneration facility 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 power production.

(17) "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.

(18) "Busbar" means the power conduit of an electricity generating facility that serves as the starting point for the electricity transmission system.

(19) "Butane" means a normally gaseous straight-chain or branch chain hydrocarbon extracted from natural gas or refinery fuel gas streams and is represented by the chemical formula C_4H_{10}. Butane includes normal butane and refinery-grade butane.

(20) "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.

(21)   "CAISO" means the California Independent System Operator.

(22)   "CAISO integrated forward market" means the electric power market conducted by the CAISO that determines the best use of resources available while finding the least cost method of procuring required components.

(23)   "CAISO markets" mean the CAISO real-time market and the CAISO integrated forward market.

(24)   "CAISO real-time market" means the electric power market conducted by the CAISO where supplemental electric power is quickly bought or sold every ten minutes to accommodate power use just moments before it occurs.

(25)   "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.

(26)   "Calcine" means to heat a substance so that it oxidizes or reduces.

(27)   "Calendar year" means the time period from January 1 through December 31.

(28)   "California Climate Action Registry" or "CCAR" means the entity established pursuant to former Health and Safety Code Section 42800 et seq.

(29)   "California eligible renewable resource" means an electricity generating facility that the California Energy Commission has certified as an eligible renewable energy resource that may be used by a retail seller of electricity to satisfy its California Renewables Portfolio Standard Program procurement requirements, consistent with Public Utilities Code sections 399.11 through 399.16 and Public Resources Code sections 25740 through 25751.

(30)   "California Energy Commission" means the California Energy Resources Conservation and Development Commission.

(31)   "Capacity factor" means the amount of energy that an electricity generating facility actually generates compared to its maximum rated output over a given period of time, usually one year.

(32) "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.

(33) "Carbon dioxide equivalent" or "CO_2 equivalent" or "CO_2e" means a measure for comparing carbon dioxide with other GHGs, based on the quantity of those gases multiplied by the appropriate global warming potential (GWP) factor and commonly expressed as metric tonnes of carbon dioxide equivalents ($MTCO_2e$).

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

(35) "Catalyst coke" means carbon that is deposited on a catalyst, thus deactivating the catalyst.

(36) "Catalytic cracking" means a refinery process of breaking down larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a catalyst.

(37) "Catalytic reforming" means a refining process using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules.

(38) "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.

(39) "Cementitious product" means cement, cement kiln dust, cement clinker, clinker dust, fly ash, slag, and other pozzolans.

(40) "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.

(41) "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.

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

(43)   "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."

(44)   "Coal-derived fuel" means any fuel, whether in a solid, liquid, or gaseous state, produced by the mechanical, thermal, or chemical processing of coal (e.g., pulverized coal, coal refuse, liquefied or gasified coal, washed coal, chemically cleaned coal, coal-oil mixtures, and coal-derived coke).

(45)   "Cogeneration facility" means an industrial structure, installation, plant, building, or self-generation facility, which may include one or more cogeneration systems configured as either a topping cycle or bottoming cycle plant.

(46)   "Cogeneration system" means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually mechanical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

(47)   "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.

(48)   "Coke burn-off" means coke removal from the surface of a catalyst by combustion during catalyst regeneration.

(49)   "Combustion emissions" means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

(50)   "Combustion source" means a source of combustion emissions.

(51)   "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 opinion of a potential client's greenhouse gas emissions, or the person or body's objectivity in performing verification services is or might be otherwise compromised.

(52) "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.

(53) "Conveying system" means a device for transporting materials from one piece of equipment or location to another location within a facility. Conveying systems include but are not limited to the following: feeders, belt conveyors, bucket elevators and pneumatic systems.

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

(55) "Crude oil" means a mixture of hydrocarbons that exists in the liquid phase and that is found in natural underground reservoirs.

(56) "De minimis" means those emissions reported for a source or sources that are calculated using alternative methods selected by the operator, subject to the limits specified in section 95103(a)(6).

(57) "Diesel fuel" means a fuel composed of distillates obtained in petroleum refining operations.

(58) "Direct emissions" means greenhouse gas emissions from sources that are under the operational control of the operator.

(59) "Distillate fuel oil" means a general classification for a petroleum fraction produced in conventional distillation operations. It includes diesel fuels and fuel oils.

(60) "Distributed emissions" means CO_2 emissions from fuel combustion at cogeneration facilities distributed between energy stream outputs including thermal energy, electricity generation and potentially other product outputs.

(61) "District heating and cooling" means the distribution of heat or cooling from one or more sources to multiple buildings.

(62) "Electricity generating facility" means generating facility.

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

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

(65) "Emissions" means the release of greenhouse gases into the atmosphere from sources and processes in a facility.

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

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

(68) "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 generating units designated as backup or emergency generators in a permit issued by an air pollution control district or air quality management district.

(69) "Ethane" means a normally gaseous straight-chained hydrocarbon that boils at a temperature of -127.48 degrees Fahrenheit with a chemical formula of C_2H_6.

(70) "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.

(71) "Executive Officer" means the Executive Officer of the ARB or his or her delegate.

(72) "Facility" means any property, plant, building, structure, stationary source, stationary equipment or grouping of stationary equipment or stationary sources 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 operational 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.

(73) "Feed" means the prepared and mixed materials, which include but are not limited to materials such as limestone, clay, shale, sand, iron ore, mill

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scale, cement kiln dust, and fly ash, that are fed to the kiln. Feed does not include the fuels used in the kiln to produce heat to form the clinker product.

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

(75) "Final point of delivery" means the last point of delivery for a given electricity transaction.

(76) "Flare" means a combustion device that uses an open flame to burn combustible gases with combustion air provided by uncontrolled ambient air around the flame. This term includes both ground-level and elevated flares. When used as a verb, the term "flare" means to combust vent gas in a flare.

(77) "Flexicoking" means a thermal cracking process which converts heavy hydrocarbons such as crude oil, tar sands bitumen, and distillation residues into light hydrocarbons.

(78) "Flexigas" means a low Btu gas produced during flexicoking.

(79) "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.

(80) "Fluid catalytic cracking unit regenerator" means the portion of the fluid catalytic cracking unit in which coke burn-off and catalyst regeneration occurs, and includes the regenerator combustion air blower(s).

(81) "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.

(82) "Fly ash" means particles of ash, such as particulate matter that may also have metals attached to them, which are carried up the stack of a combustion unit with gases during combustion.

(83) "Fossil fuel" means a fuel, such as coal, oil, and natural gas, produced by the decomposition of ancient (fossilized) plants and animals.

(84) "Fuel" means solid, liquid or gaseous combustible material.

(85)   "Fuel analytical data" means any data collected about the mass, volume, flow rate, heat content, or carbon content of a fuel.

(86)   "Fugitive emissions" means the unintended or incidental emissions of greenhouse gases from the transmission, processing, storage, use, or transportation of fossil fuels or other materials, including but not limited to HFCs from refrigeration leaks, SF_6 from electric power distribution equipment, methane from mined coal, and CO_2 emitted from geyser steam and/or fluid used in geothermal generating facilities.

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

(88)   "Full verification" means all verification services as provided in section 95131.

(89)   "General stationary combustion facility" means a facility not otherwise subject to sector-specific reporting requirements that emits $\geq$25,000 metric tonnes of CO_2 in 2008 or any subsequent year from stationary combustion sources.

(90)   "Generating facility" means a facility that generates electricity and includes one or more generating units at the same location.

(91)   "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.

(92)   "Global warming potential" or "GWP factor" means the radiative forcing impact of one mass-based unit of a given greenhouse gas relative to an equivalent unit of carbon dioxide over a given period of time.

(93)   "Greenhouse gas," "greenhouse gases" or "GHG" means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

(94)   "Greenhouse gas source" means any physical unit, process, or other use or activity that releases a greenhouse gas into the atmosphere.

(95)   "Gross generation" means the total electrical output of the generating unit, expressed in megawatt hours (MWh) per year.

(96)   "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.

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

(98) "Hydrofluorocarbons" or "HFCs" means a class of GHGs primarily used as refrigerants, consisting of hydrogen, fluorine, and carbon.

(99) "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.

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

(101) "Indirect energy" means electricity, thermal, or other energy sources provided by a retail provider or facility not owned or operated by the user of the energy.

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

(103) "Kerosene" means a light distillate fuel that includes No. 1-K and No. 2-K as well as other grades of range or stove oil that have properties similar to those of No. 1 fuel oil.

(104) "Kiln" means a device, including any associated preheater or precalciner devices, that produce clinker by heating limestone and other materials for subsequent production of Portland or other cement.

(105) "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).

(106) "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.

(107) "Less intensive verification" means the verification services provided in interim years between full verifications; less intensive verification only requires data checks on an operator's emissions data report based on the most current sampling plan developed as part of the most current full verification services.

(108) "Liquefied petroleum gas" or "LPG" means a group of hydrocarbon-based gases derived from crude oil refining or natural gas fractionation. They

include propane, propylene, normal butane, butane, butylene, isobutene and isobutylene. For convenience of transportation, these gases are liquefied through pressurization.

(109)   "Long-term power contract" means a power contract with a term of five years or more.

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

(111)   "Low Heating Value" or "LHV" means low or net heat content with the heat of vaporization excluded. The water is assumed to be in the gaseous state.

(112) "Marketer" means a purchasing/selling entity that is not a retail provider, and that is the purchaser/seller at the first point of delivery in California for electric power imported into California, or the last point of receipt in California for power exported from California.

(113) "Material misstatement" means one or more inaccuracies identified in the course of verification that result in the total reported emissions, or reported purchases, sales, imports or exports of electricity, being outside the 95 percent accuracy required to receive a positive verification opinion.

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

(115) "Metric tonne" or "MT" or "tonne" means a common international measurement for the quantity of GHG emissions, equivalent to about 2204.6 pounds or 1.1 short tons.

(116) "MMBtu" means million British thermal units.

(117) "Mobile combustion emissions" means emissions from the transportation of materials, products, waste, and employees resulting from the combustion of fuels in company owned or controlled mobile combustion sources.

(118) "Mobile combustion source" means a source of greenhouse gas emissions resulting from combustion by a vehicle or other non-stationary, self-propelled combustion source that produces greenhouse gas emissions including, but not limited to, passenger cars, large/heavy duty truck cabs and chassis, light and medium duty trucks and vans, motorcycles, public transit buses, or military tanks or other tracked military vehicles, mobile cranes, bulldozers, concrete mixers, street cleaners, golf carts, all terrain

vehicles, trains, airplanes, boats, ships, implements of husbandry, and hauling equipment used inside and around airports, docks, depots, industrial, and commercial plants.

(119) "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 degrees Fahrenheit at the 10-percent recovery point to 365 to 374 degrees Fahrenheit at the 90-percent recovery point.

(120) "Multi-jurisdictional retail provider" means a retail provider that provides electricity to end users in California and in one or more other states.

(121) "NAICS" means North American Industry Classification System.

(122) "Nameplate generating capacity" means the maximum rated output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

(123) "Naphtha" means a generic term applied to a petroleum fraction with an approximate boiling range between 122 degrees Fahrenheit and 400 degrees Fahrenheit.

(124) "Natural gas" means a naturally occurring mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions.

(125) "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.

(126) "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 control areas.

(127) "No. 1 diesel fuel" means a light distillate fuel oil that meets the specifications of ASTM (American Society for Testing and Materials) Specification D396 07.

(128) "No. 1 distillate" means a petroleum distillate that can be used as either a diesel fuel or a fuel oil.

(129) "No.1 fuel oil" means a light petroleum distillate fuel oil that meets the specifications of ASTM Specification D396-07.

(130) "No. 2 diesel fuel" means a distillate fuel oil that meets the specifications of ASTM Specification D975–07b.

(131) "No. 2 distillate" means a petroleum distillate that can be used as either a diesel fuel or a fuel.

(132) "No. 2 fuel oil" or "heating oil" means a distillate fuel oil that meets the specifications defined in ASTM D396-07.

(133) "No. 4 fuel oil" means a distillate fuel oil made by blending distillate fuel oil and residual fuel oil stocks that conforms with ASTM Specification D396-07.

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

(135) "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.

(136) "North American Industry Classification System" or "NAICS" means a standard for use by Federal statistical agencies in classifying business establishments for the collection, analysis, and publication of statistical data related to the business economy of the United States.

(137) "Null power" means any electricity produced by a renewable energy electricity generating facility from which a Western Renewable Energy Generation Information System (WREGIS) or a Nevada Tracks Renewable Energy Credits (NVTREC) certificate has been unbundled and sold separately.

(138) "NVTREC" means Nevada Tracks Renewable Energy Credits.

(139) "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.

(140) "Operator" means the entity having operational control of a facility, or other entity, from which an emissions data report is required under this article. For purposes of reporting electricity transactions as required in

section 95111 "operator" means a retail provider, marketer, or facility operator.

(141) "Pacific Northwest" or "PNW" means Washington, Oregon, Idaho, Montana, and British Columbia.

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

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

(144) "Petroleum coke" means a residue high in carbon content and low in hydrogen that is the final product of thermal decomposition in the condensation process in cracking.

(145) "Petroleum refinery" or "refinery" means any facility engaged in producing gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

(146) "Point of delivery" means a point on an electric system where a power supplier delivers electricity to the receiver of that energy. 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.

(147) "Point of receipt" means a point on an electric system where an entity receives electricity from a supplier. This point can be an interconnection with another system or a generator busbar.

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

(149) "Portable" is as defined in title 17, California Code of Regulations, section 93116.2(a)(28).

(150) "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.

(151) "Positive verification opinion" means a verification opinion rendered by a verification body stating that the verification body can say with reasonable

assurance that the submitted emissions data report is free of material misstatement and includes a qualifying statement that the emissions data report conforms to the requirements of this article.

(152) "Power" means electricity, except where the context makes clear that another meaning is intended.

(153) "Power contract" means an arrangement for the purchase of electricity. Power contracts may be, but are not limited to, power purchase agreements and tariff provisions.

(154) "Pressure swing adsorption" or "PSA" means a gas purification process which selectively concentrates target gas molecules using porous, high surface area solid adsorbents and elevated pressure.

(155) "PSA off-gas" or "tail-gas" means the impurity stream resulting from the sequential PSA pressurization/depressurization purification process.

(156) "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.

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

(158) "Process emissions" means greenhouse gas emissions other than combustion emissions occurring as a result of a process.

(159) "Process gas" means any gas generated by an industrial process such as petroleum refining.

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

(161) "Professional judgment" means the ability to render sound decisions based on professional qualifications and relevant greenhouse gas accounting experience.

(162) "Propane" means a normally straight chain hydrocarbon that boils at -43.67 degrees Fahrenheit and is represented by the chemical formula C_3H_8.

(163) "Purchasing/selling entity" means an entity that is eligible to purchase or sell energy or capacity and reserve transmission services.

(164) "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.

(165) "Purge gas" means nitrogen, carbon dioxide, liquefied petroleum gas, or natural gas used to maintain a non-explosive mixture of gases in a flare header or provide sufficient exit velocity to prevent regressive flame travel back into the flare header.

(166) "Qualifying facility" means a cogeneration or small power production facility that meets ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission (FERC) pursuant to the Public Utility Regulatory Policies Act.

(167) "Reasonable assurance" means a high degree of confidence that submitted data and statements are valid.

(168) "Recycled" means a material that is reused or reclaimed.

(169) "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.

(170) "Renewable energy" means energy from sources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy includes, but is not limited to, energy derived from solar, wind, geothermal, hydroelectric, wood, biomass, tidal power, sea currents, and ocean thermal gradients.

(171) "Report year" means the calendar year for which emissions are being reported in the emissions data report.

(172) "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.

(173) "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 9604, community choice aggregator as

defined in Public Utilities Code section 331.1, or the Western Area Power Administration.

(174) "Screening value" or "SV" means the instrument reading (ppmv) obtained when components, including but not limited to valves, pump seals, connectors, flanges, open-ended lines and other equipment components, are evaluated for leakage as described in United States Environmental Protection Agency (U.S. EPA) Method 21 – Determination of Volatile Organic Compound Leaks (1981).

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

(176) "Self-generation facility" means a facility dedicated to serving a particular end user, usually located on the user's premises. The facility may either be owned directly by the end user or owned by an entity with a contractual arrangement to provide electricity to meet some or all of the user's load.

(177) "Small refiner" is as defined in Title 13, California Code of Regulations, section 2260(a)(32).

(178) "Source" means greenhouse gas source, as defined in this section.

(179) "Southwest" or "SW" means Arizona, Nevada, Utah, Colorado, and western New Mexico.

(180) "Specified source of power" or "specified source" means a particular generating unit or facility for which electrical generation can be confidently tracked due to full or partial ownership or due to its identification in a power contract including any California eligible renewable resource.

(181) "Standard conditions" or "STP" or "standard temperature and pressure" means a temperature of 20 degrees Celsius (68 degrees Fahrenheit) and an absolute pressure of 760 mm (30 inches) of mercury or 60 degrees Fahrenheit and 1 atmosphere.

(182) "Standard cubic foot" or "scf" means the amount of gas that would occupy a volume of one cubic foot if free of combined water at standard conditions.

(183) "Stationary" means neither portable nor self propelled, and operated at a single facility.

(184) "Stationary combustion source" means a stationary source of combustion emissions, and for the purposes of this article does not include portable

equipment, backup generators, or emergency generators as specified in section 95101(c)(2) and section 95101(c)(3).

(185) "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.

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

(187) "Sulfur recovery unit" or "SRU" means a process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

(188) "Supplemental firing" means an energy input to the cogeneration facility used only in the thermal process of a topping cycle plant, or in the electricity generating or manufacturing process of a bottoming cycle plant.

(189) "Tactical support equipment" is as defined in title 17, California Code of Regulations, section 93116.2(a)(36).

(190) "Thermal host" means the user of the steam or heat output of a cogeneration facility.

(191) "Ton" means a short ton equal to 2000 pounds.

(192) "Topping cycle plant" means a cogeneration facility in which the energy input to the facility is first used to produce useful power output, and at least some of the reject heat from the power production process is then used to provide useful thermal output.

(193) "Total organic carbon" or "TOC" means a measure of the total organic carbon molecules present in a sample.

(194) "Transferred CO_2" means carbon dioxide that is not emitted directly at the facility but is sold and/or transferred out of the installation as a pure substance.

(195) "Uncertainty" means the degree to which data or a data system is deemed to be indefinite or unreliable.

(196) "Unspecified source of power" or "unspecified source" means electricity generation that cannot be matched to a particular generating facility. Unspecified sources of power may include power purchased from entities that own fleets of generating facilities such as independent power

producers, retail providers, and federal power agencies and power purchased from electricity marketers, brokers, and markets.

(197) "Useful power output" means the electric or mechanical energy made available for use, exclusive of any such energy used in the power production process.

(198) "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.

(199) "Verification" means the process used to ensure that an operator's emissions data report is free of material misstatement and complies with ARB's procedures and methods for calculating and reporting GHG emissions.

(200) "Verification body" means a firm or AQMD/APCD, accredited by ARB, that is able to render a verification opinion and provide verification services for operators subject to reporting under this article.

(201) "Verification cycle" means one year of full verification and the next consecutive two years of less intensive verification for operators subject to annual verification. For operators subject to triennial verification, a verification cycle means one year of full verification, and if elected, the next consecutive two years of less intensive verification. A verification cycle cannot exceed three calendar years.

(202) "Verification opinion" means the final opinion rendered by a verification body attesting whether an operator's emissions data report is free of material misstatement and a qualifying statement whether the emissions data report conforms to the requirements of this article.

(203) "Verification services" means services provided during verification as specified in section 95131, including but not limited to reviewing an operator's emissions data report, verifying its accuracy according to the standards specified in this article, assessing the operator's compliance with this article, and submitting a verification opinion to the ARB.

(204) "Verification team" means all of those working for a verification body, including all subcontractors, to provide verification services for an operator. The lead verifier for the verification team shall be a lead verifier in the verification body.

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

(206) "Volatile organic compounds" 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.

(207) "Waste-derived fuel" means a fuel typically derived from waste(s) and generally used as a substitute for conventional fossil fuels. Waste-derived fuels can include fossil fuels such as waste oil, plastics, or solvents; biomass such as dried sewage or impregnated saw dust; or fractions of both fossil fuels and biomass such as municipal solid waste or tires.

(208) "Wastewater" means any process water which contains oil, emulsified oil, or other organic compounds that are not recycled or otherwise used in a facility.

(209) "Wastewater separator" means equipment used to separate oils and water from locations downstream of process drains.

(210) "WREGIS" means Western Renewable Energy Generation Information System.

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

§ 95103. General Greenhouse Gas Reporting Requirements.

(a) ***General Reporting Requirements.*** The operators listed in section 95101(b), except as provided in section 95103(e), shall submit greenhouse gas emissions data reports on the schedule specified in section 95103(b).

(1) The operator shall submit a report for the 2008 report year that applies best available data and methods to develop emissions estimates. The operator shall submit reports for 2009 and subsequent report years that meet all specifications of this article.

(2) ***Stationary Sources.*** The operator shall identify, calculate, and report CO_2, N_2O, CH_4, SF_6, HFC, and PFC emissions from stationary combustion, process, and fugitive sources at the facility as specified in sections 95110 through 95115. The operator shall calculate and report each GHG separately for each fuel type used. The operator shall monitor and report fuel consumption for the facility, and for each process unit or group of units where fuel use is separately metered.

(3) The operator shall separately identify, calculate and report all direct emissions of CO_2 resulting from combustion of biomass-derived fuels as specified in sections 95110 through 95115.

(4) ***Mobile Sources.*** The operator may elect to identify, calculate, and separately report facility CO_2, N_2O, and CH_4 emissions from mobile combustion. For those gases selected for voluntary reporting, the operator shall calculate mobile combustion emissions using the methods specified in section 95125(i).

(5) The operator shall separately calculate and report consumption of purchased or acquired electricity, heat, cooling or steam when specified in sections 95110 through 95115.

(6) ***Emissions Calculation and Reporting Procedures for De Minimis Sources.*** The operator may elect to designate as *de minimis* one or more sources that collectively produce no more than 3 percent of the facility's total CO_2 equivalent emissions, not to exceed 20,000 metric tonnes CO_2 equivalent emissions. The operator may estimate emissions for these *de minimis* sources using alternative methods of the operator's choosing, subject to the concurrence of the verification team that the use of such methods provides reasonable assurance that the emissions so designated and estimated do not exceed the applicable *de minimis* limits. The operator shall separately identify and include in the emissions data report the emissions from designated *de minimis* sources. The operator shall determine CO_2 equivalence according to the 100-year global warming potentials provided in Appendix A.

(7) The operator shall report information in the units of measurement specified in sections 95110 through 95115.

(8) **Fuel Analytical Data Capture.** When the applicable emissions estimation methodologies in sections 95110 through 95125 require periodic collection of fuel analytical data for an emissions source, the operator shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 percent for each report year.

    (A) If the operator is unable to obtain fuel analytical data such that more than 20 percent of emissions from a source cannot be directly accounted for, and the source for which data are missing is not subject to separate fuel analytical data capture requirements specified in 40 CFR Part 75 or Part 60, the emissions from that source shall be considered unverifiable for the report year.

    (B) If the fuel analytical data capture rate is at least 80 percent but less than 100 percent for any emissions source identified in sections 95110 through 95125, and that source is not subject to separate fuel analytical data capture requirements specified in 40 CFR Part 75 or Part 60, the operator shall use the mean of the fuel analytical data results captured to substitute for the missing values for the period of missing data.

(9) **Fuel Use Measurement Accuracy.** The operator shall employ procedures for fuel use data measurements (mass or volume flow) used to calculate GHG emissions that quantify fuel use with an accuracy within ±5 percent. All fuel use measurement devices shall be maintained and calibrated in a manner and at a frequency required to maintain this level of accuracy. The operator shall make available to the verification team documentation to support this level of accuracy. The operator who measures solid fuels shall validate fuel consumption estimates with belt or conveyor scale calibrations conducted at least quarterly, and retain record of such calibrations.

(10) *Procedure for Interim Fuel Analytical Data Collection.*

    (A) In the event of an unforeseen breakdown of fuel analytical data monitoring equipment required for the emissions estimation methodologies in sections 95110 through 95125, the Executive Officer may authorize an operator to use an interim data collection procedure if the Executive Officer determines that the operator has satisfactorily demonstrated that:

        1. The breakdown may result in a loss of more than 20 percent of the source's fuel data for the reporting year, such that emissions

for the affected source could not be verified under the provisions of section 95103(a)(8)(A);

2. The fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting the facility operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;

3. The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and

4. The request was submitted within 30 calendar days of the breakdown of the fuel analytical data monitoring equipment.

(B) An operator seeking approval of an interim data collection procedure must, within 30 days of the monitoring equipment breakdown, submit a written request to the Executive Officer that includes all of the following:

1. The proposed start date and end date of the interim procedure;
2. A detailed description of what data are affected by the breakdown;
3. A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the operator's usual equipment-based method;
4. A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data; and
5. A demonstration that the proposed interim procedure meets the criteria specified in section 95103(a)(10)(A).

(C) The Executive Officer may limit the duration of the interim data collection procedure or include other conditions of approval to ensure the criteria in section 95103(a)(10)(A) are met.

(D) 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 section 95103(a)(8). When approving 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(b)(11) of this article.

(11) Where this article specifies a choice between use of a fuel-based calculation or use of a continuous emissions monitoring system (CEMS) to calculate

CO_2 emissions, the operator shall make this choice and continue to use the method chosen for all future emissions data reports. When an operator elects to install a new CEMS prior to January 1, 2011, the operator may report combustion emissions on the basis of the fuel-based calculation specified in this article for the 2008, 2009, and 2010 report years. The new CEMS shall be installed and operated according to requirements in section 95125(g), and become operational for purposes of emissions reporting by January 1, 2011.

(b) **Reporting Schedule – Existing Facilities.** Operators of the facilities and entities listed in section 95101(b), except as provided in section 95103(e), that are operational as of January 1, 2008, must submit emissions data reports to ARB in 2009 and each subsequent calendar year. Operators shall submit these reports as specified in the following schedule.

   (1)   The following operators subject to the requirements of this article shall submit a complete emissions data report to the ARB no later than April 1 of each calendar year beginning in 2009, for emissions occurring in the previous calendar year:
   (A)   Operators of general stationary combustion facilities, excluding oil and gas facilities with a NAICS code of 211111;
   (B)   Operators of electricity generating facilities and cogeneration facilities not under the operational control of any of the following: a retail provider, cement plant operator, petroleum refinery operator, hydrogen plant operator, or operator of an oil and gas facility with a NAICS code of 211111.

   (2)   The following operators subject to the requirements of this article shall submit a complete GHG emissions data report to the ARB no later than June 1 of each calendar year beginning in 2009, for emissions occurring in the previous calendar year:
   (A)   Retail providers;
   (B)   Marketers;
   (C)   Operators of general stationary combustion facilities within the oil and gas sector with a NAICS code of 211111;
   (D)   Operators of cement plants;
   (E)   Operators of petroleum refineries;
   (F)   Operators of hydrogen plants.

(c) **Verification – Existing Facilities.** Operators of all facilities subject to the reporting requirements of this article shall obtain verification services for emissions data reports submitted in 2010 and subsequent years from a verification body that meets the requirements of sections 95131 through 95133. Verification shall be obtained as provided in the following schedule.

(1) **Annual Schedule.** The following shall obtain verification of each annual emissions data report:
  (A) Retail providers, marketers, and operators of petroleum refineries and hydrogen plants;
  (B) Operators of general stationary combustion facilities in the oil and gas sector identified by NAICS code of 211111;
  (C) Operators of electricity generating and cogeneration facilities that combust fossil fuels and have a total nameplate generating capacity ≥10 MW.

(2) **Triennial Schedule.** The following shall obtain verification of the emissions data report submitted in 2010, and shall obtain verification of the emissions data reports submitted every third year thereafter:
  (A) Operators of cement plants; however, if any change in materials or operations occurs at a cement plant that requires a change in a permit filed with an air pollution control district or air quality management district, the operator of the cement plant shall obtain verification of the emissions data report that covers the first full calendar year following the permit change, in addition to the regular triennial schedule;
  (B) Operators of electricity generating or cogeneration facilities that combust pure biomass fuels, or geothermal generating facilities;
  (C) Operators of electricity generating or cogeneration facilities that have a total nameplate generating capacity <10 MW;
  (D) Operators of general stationary combustion facilities, excluding oil and gas sector facilities identified by NAICS code 211111.

(3) **Verification Opinion Due Dates.** In the calendar years when verification is required, the verification body shall submit to the ARB the verification opinion specified in section 95131(c)(1) no later than six months after the deadlines specified in section 95103(b) for submitting emission reports.
  (A) For operators having an emissions data report due April 1, as specified in section 95103(b)(1), the verification opinion must be submitted no later than October 1 of the same calendar year;
  (B) For operators having an emissions data report due June 1, as specified in section 95103(b)(2), the verification opinion must be submitted no later than December 1 of the same calendar year.

(d) **Reporting Schedule – New Facilities.** Any operator described in section 95101(b) that commences operations at a new facility after January 1, 2008 shall submit an initial emissions data report for that facility based on emissions produced during the first full calendar year of operation. The emissions data report and a verification opinion shall be submitted during the year following the first full calendar year of operation according to the schedule in sections 95103(b) and (c), with reports for subsequent years due as required by the same schedule. This paragraph does not apply to changes in ownership, management, or operations at existing facilities.

(e) *Cessation of Reporting After Reduced Emissions.*

    (1)   When the operation of a general stationary combustion facility, refinery, or hydrogen plant subject to the requirements of this article is changed such that the operator has reported less than 20,000 metric tonnes of CO_2 from combustion for three consecutive report years, the operator shall be exempted from further reporting until CO_2 emissions from combustion again exceed 25,000 metric tonnes in any calendar year.

    (2)   When the operation of an electricity generating or cogeneration facility subject to this article is changed such that the operator has reported less than 2,000 metric tons of CO_2 for three consecutive report years, the operator shall be exempted from further reporting until CO_2 emissions again exceed 2,500 metric tonnes in any calendar year.

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

§ 95104.   Greenhouse Gas Emissions Data Report.

(a) *Emissions Data Report.* Operators subject to this article shall submit emissions data reports according to the schedule and requirements specified in section 95103, except as provided in section 95103(e). Emissions data reports shall include the information below and the additional data specified in sections 95110 through 95115, as applicable.

    (1)   Facility name, identification number, physical address, mailing address, location, NAICS code;
    (2)   A description of facility geographic location;
    (3)   Name and contact information including email address and telephone number, of the operator submitting the emissions report and the person primarily responsible for preparing and submitting the emissions report;
    (4)   The report year;
    (5)   The direct emissions, electricity transactions information, and other data specified in sections 95110 through 95115 as applicable to the operator, including emissions occurring during routine maintenance, start-ups, shutdowns, upsets and downtime;
    (6)   Indirect energy consumed for electricity, heat, steam, and cooling when required for the facility as specified in sections 95110 through 95115;
    (7)   Efficiency metrics when required for the facility as specified in sections 95110 through 95115;
    (8)   The parent company or companies of the operator, along with:

(A) A list of all facilities and offices in California owned or operated by that parent company or companies, directly or through a subsidiary, that emit direct GHG emissions from combustion that is not for the purpose of facility space heating, including facilities and offices not subject to the requirements of this article;

(B) Contact information for the facilities and offices provided in section 95104(a)(8)(A), including physical addresses, e-mail addresses if available, and telephone numbers;

(C) The operator may elect to have information required by sections 95104(a)(8)(A)-(B) submitted separately by the parent company for all facilities under the ownership or operational control of the parent company or its subsidiaries;

(D) The operator may also elect to provide a single contact person, e-mail, and phone contact for all facilities listed under the requirements of 95104(a)(8)(A)-(B);

(E) Information provided under section 95104(a)(8) is not subject to the verification requirements of this article.

(9) Emission factors developed or measured by the operator using approved source testing as provided under sections 95125(b)(4) or 95125(h)(3). Emission factors shall be provided in units of emissions per amount of fuel consumed, where fuel is reported in units of either scf for gases, gallons for liquids, short tons for non-biomass solids, or bone dry tons for biomass-derived solid fuels.

(10) A signed and dated statement provided by the operator that the report has been prepared in accordance with this article, and that the statements and information contained in the emissions data report are true, accurate, and complete.

(b) *Maintaining the GHG Inventory Program.* To facilitate annual compilation of the emissions data report, the operator shall maintain a greenhouse gas inventory program that ensures that emissions calculations and electricity transactions information are transparent, accurate, and independently verifiable. The operator shall establish, document, implement, and maintain data acquisition and handling activities for the calculation and reporting of greenhouse gas emissions. Such activities shall include measuring, monitoring, analyzing, recording, processing and calculating the parameters specified by this article.

(c) *Data Completeness.* The operator shall establish, document, implement and maintain a system that provides clarity, transparency, and completeness of data sufficient to facilitate replication of the emissions and electricity transactions information reported as specified by this article. The operator shall make every reasonable effort to complete emissions data reports that contain no material misstatement and are in conformance with the emission calculation methodologies and factors specified by this article. The operator shall implement

systems of internal audit, quality assurance, and quality control for the reporting program and the data reported.

(d) **Revisions.** The operator may revise a submitted emissions data report under the circumstances specified in section 95104(d)(1)-(3). The operator shall maintain documentation to support any revisions made to a previously submitted emissions data report. Documentation for all emissions data report revisions shall be retained by the operator for five years, as specified in section 95105.

(1) If during the course of receiving verification services and prior to completion of a verification opinion an operator chooses to make a correction or improvement to the report;

(2) If an operator wishes to correct or improve an emissions data report not subject to verification, provided those changes are documented and approved by ARB;

(3) If, within five years of submittal, an operator wishes to correct or improve an emissions data report that has received a positive verification opinion, in which case the revision must also be made subject to verification.

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

§ 95105.   Document Retention and Record Keeping Requirements.

(a) The operator shall establish and maintain procedures for document retention and record keeping. The operator shall retain documents regarding the design, development and maintenance of the GHG inventory, in paper, electronic or other usable format, for a period of not less than five years following submission of each emissions data report. The retained documents, including GHG emissions data, shall be sufficient to allow for the verification of each emissions data report.

(b) Upon request by ARB, the operator shall provide to ARB within 20 working days all documents, including data, used to develop an emissions data report.

(c) In addition to information submitted as part of the emissions data report, each operator shall retain, at a minimum, the following information for at least five years after the submission of the report:

(1) The list of all sources included in the emission estimates;
(2) The fuel use data used to calculate emissions for each source, categorized by process and fuel or material type;

(3) Documentation of the process for collecting fuel use data for the facility and its sources;

(4) Any GHG emissions calculations and methods used;

(5) All emission factors used for emission estimates, including documentation for any factors not provided by ARB;

(6) Any facility or other input data used for emission estimates;

(7) Documentation of biomass fractions for specific fuels;

(8) Record of electric power purchase and sale transactions, including imports and exports of power into and from California;

(9) The fuel use data, emissions, or other data submitted to the ARB under this article including the emissions data report;

(10) Names and documentation of key facility personnel involved in emissions calculating and reporting;

(11) Any other information that is required for the verification of the emissions data report.

(12) A log to be prepared for each reporting year, beginning January 1, 2009, documenting all procedural changes made in GHG accounting methods and changes to instrumentation critical to GHG emissions determination.

(d) For measurement based methodologies, each operator shall retain the following information for at least five years after the submission of the emissions data report:

(1) The list of all emission sources monitored;

(2) Collected monitoring data;

(3) The data used to assess the accuracy of emissions from each emissions source, categorized by process;

(4) Quality assurance and quality control information including information regarding any measurement gaps;

(5) The data used for the corroborating calculations;

(6) A detailed technical description of the continuous measurement system, including documentation of any findings and approvals by federal, State or local agencies;

(7) Raw and aggregated data from the continuous measurement system; including documentation of changes over time and the log book on tests, down-times, calibrations, servicing and maintenance;

(8) Documentation of any changes in continuous measurement systems.

NOTE: Authority cited: Sections 39600, 39601, 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.

(b) Any entity submitting information to the ARB pursuant to this article may designate information that is not emissions data as confidential because it is a trade secret or otherwise exempt from public disclosure under the California Public Records Act (Government Code section 6250 et seq.). All such requests for confidentiality shall be handled in accordance with the procedures specified in title 17, California Code of Regulations, sections 91000 to 91022.

NOTE: Authority cited: Sections 38580, 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 38580, 39600, 41511, and 38530, Health and Safety Code.

§ 95107.   Enforcement.

(a) Knowing submission of false information, with intent to deceive, to the Executive Officer or a verification body, shall constitute a single, separate violation of the requirements of this article for each day after the information has been received by the Executive Officer.

(b) Failure to submit any report or to include in a report all information required by this article, or late submittal of any report, shall constitute a single, separate violation of this article for each day that the report has not been submitted beyond the specified reporting date. For the purposes of this section, "report" means any emissions data report, verification opinion, or other document required to be submitted by this article.

NOTE: Authority cited: Sections 38580, 39600, 39601, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 38580, 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, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

§ 95109. Incorporation by Reference.

The following documents are incorporated by reference into this article. These materials are incorporated as they exist on the date this article is adopted.

(a) American Society for Testing and Materials (ASTM) D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), ASTM D240-02 (Reapproved 2007), ASTM D4809-00 (Reapproved 2005), ASTM 5373-02 (Reapproved 2007), ASTM D5291-02 (Reapproved 2007), ASTM D3238-95 (Reapproved 2005), ASTM D2502-04, ASTM D2503-92 (Reapproved 2002), ASTM D1945-03, ASTM D1946-90 (Reapproved 2006), ASTM D6866-06a, ASTM D388-05, ASTM D5468-02 (Reapproved 2007), ASTM D240-87 (Reapproved 1991), ASTM D5865-07a, ASTM Specification D396-07, ASTM Specification D975-07b.

(b) *California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities*, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board (ARB), February 1999.

(c) *Control of Emissions from Refinery Flares*, Rule 1118, South Coast Air Quality Management District, Amended November 4, 2005.

(d) *U.S. EPA TANKS Version 4.09D*, US Environmental Protection Agency, October 2005.

(e) Gas Processors Association (GPA) Standard 2261-00, Revised 2000.

NOTE: Authority cited: Sections 39600, 39601, 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

§ 95110. Data Requirements and Calculation Methods for Cement Plants.

(a) *Greenhouse Gas Emissions Data Report.* The operator of a cement plant specified in section 95101(b) shall include the following information in the emissions data report for each report year.

   (1)   Total emissions, including:
         (A)   Total CO_2 emissions (metric tonnes),
         (B)   Total CH_4 emissions (metric tonnes), and
         (C)   Total N_2O emissions (metric tonnes).

   (2)   Process CO_2 emissions from cement manufacturing using the following calculation methods:
         (A)   Clinker based methodology for CO_2 estimates shall include:
               1.   Clinker emission factor (kg CO_2/metric tonne clinker) including:
                    a.   Quantity of clinker produced (metric tonnes),
                    b.   Lime (CaO) content of clinker (percent),
                    c.   Magnesium Oxide (MgO) content of clinker (percent),
                    d.   Non-carbonate CaO (percent), and
                    e.   Non-carbonate MgO (percent);
               2.   Cement kiln dust (CKD) emission factor (kg CO_2/metric tonne clinker) including,
                    a.   Plant specific CKD calcination rate (unitless), and
                    b.   Quantity of CKD discarded (metric tonnes); and
               3. CO_2 emissions from clinker production (metric tonnes).

         (B)   Total organic carbon (TOC) content in raw materials including:
               1.   Amount of raw material consumed in the report year (metric tonnes),
               2.   Organic carbon content of raw material (percent), and
               3. CO_2 emissions from TOC in Raw Materials (metric tonnes).

   (3)   Stationary combustion emissions, including:
         (A)   Fuel consumption by fuel type, separately for kiln and non-kiln units, 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 solid fuels;
         (B)   Average carbon content as a percent by fuel type if measured or provided by fuel supplier;

(C) Average high heat value (HHV) by fuel type if measured or provided by fuel supplier, reporting in units of MMBtu per fuel unit as specified in section 95110(a)(3)(A);

(D) CO_2 emissions by fuel type (metric tonnes), separately for kiln and non-kiln units, including separately calculated and identified CO_2 emissions from biomass-derived fuels (metric tonnes);

(E) CH_4 emissions by fuel type (metric tonnes); and,

(F) N_2O emissions by fuel type (metric tonnes).

(4) Fugitive emissions, including:
(A) Coal consumption by coal type (short tons),
(B) Emission factor (million standard cubic feet (scf) CH_4/metric tonne), and
(C) CH_4 emissions from coal storage (metric tonnes).

(5) Indirect energy usage, including:
(A) Electricity purchases from each electricity provider (kWh), and
(B) Steam, heat, and cooling purchases from each energy provider (Btu).

(6) Efficiency metrics, using both of the following calculation methods:
(A) CO_2 emissions per metric tonne of cementitious product, including:
1. Amount of own clinker consumed (metric tonnes),
2. Amount of clinker added to stock (metric tonnes),
3. Amount of clinker sold directly (metric tonnes),
4. Amount and type of clinker substitutes consumed for blending (metric tonnes), and
5. Amount and type of cement substitutes consumed for blending (metric tonnes).
(B) CO_2 emissions per metric tonne of clinker, including:
1. Amount of own clinker consumed (metric tonnes),
2. Amount of clinker added to stock (metric tonnes), and
3. Amount of clinker sold directly (metric tonnes).

(b) **Calculation of CO_2, N_2O, and CH_4 Emissions.** Operators of cement plants shall calculate emissions and indirect energy usage for each source as specified in this section.

(1) **Total CO_2 Emissions.** Operators of cement plants shall calculate total CO_2 emissions using either (A) or (B) below.

(A) Continuous emissions monitoring systems (CEMS) as specified in section 95125(g). Operators of cement plants that measure CO_2 emissions using CEMS shall also report fuel usage by fuel type.

(B) Process CO_2 emissions from cement manufacturing as specified in section 95110(c) and stationary combustion CO_2 emissions as specified in section 95110(d).

(2) **N₂O and CH₄ Emissions.** Operators of cement plants shall calculate total N_2O and CH_4 emissions from fuel combustion as specified in section 95125(b).

(3) **Fugitive Emissions.** Operators of cement plants shall calculate fugitive CH_4 emissions from coal fuel storage as specified in section 95125(j).

(4) **Indirect Energy Usage.** Operators of cement plants shall calculate indirect electricity and thermal energy purchased or acquired and consumed as specified in sections 95125(k)-(l).

(5) **Electricity Generating Units.** Operators of cement plants with electricity generating units subject to the requirements of this article shall also meet the requirements of section 95111.

(6) **Cogeneration.** Operators of cement plants with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(7) **Efficiency Metrics.** Operators of cement plants shall calculate CO_2 emissions per metric tonne of cementitious product and per metric tonne of clinker as specified in section 95110(e).

(c) **Process CO₂ Emissions from Cement Manufacturing.** Operators of cement plants shall calculate CO_2 emissions from clinker production using the Clinker-Based Methodology as specified in section 95110(c)(1). Operators shall also calculate CO_2 process emissions from the total organic carbon (TOC) content in raw materials as specified in section 95110(c)(2).

(1) **Clinker-Based Methodology.** Operators of cement plants shall calculate CO_2 emissions from clinker production using a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

Clinker-Based Methodology

CO_2 Emissions (metric tonnes) = [(Cli) * (EF$_{Cli}$)] + [(CKD) * (EF$_{CKD}$)]

Where:
Cli   =   Quantity of clinker produced, metric tonnes
EF$_{Cli}$ =   Clinker emission factor, metric tonnes CO_2/metric tonne clinker
              computed as specified in section 95110(c)(1)(A)
CKD   =   Quantity CKD discarded, metric tonnes
EF$_{CKD}$ =   CKD emission factor, computed as specified in section
              95110(c)(1)(B)

(A) ***Clinker Emission Factor (EF_Cli).*** Cement plant operators shall calculate a plant-specific clinker emission factor for each report year based on the percent of measured CaO and MgO content in the clinker and adjusted to account for non-carbonate CaO and MgO using the Clinker Emission Factor equation specified in this section, 95110(c)(1)(A). Each fraction of non-carbonate sources (e.g., steel slag, calcium silicates or fly ash) of CaO and MgO shall be subtracted from the total amount of CaO and MgO content of the clinker.

Clinker Emission Factor:

EF_{Cli} = [(CaO content – non-carbonate CaO) * Molecular ratio of CO_2/CaO] + [(MgO Content – non-carbonate MgO) * Molecular Ratio of CO_2/MgO]

Where:

CaO Content (by weight)	=	CaO content of Clinker (%)
Molecular Ratio of CO_2/CaO	=	0.785
MgO Content (by weight)	=	MgO content of Clinker (%)
Molecular Ratio of CO_2/MgO	=	1.092
Non-carbonate CaO (by weight)	=	Non-carbonate CaO of Clinker (%)
Non-carbonate MgO(by weight)	=	Non-carbonate MgO of Clinker (%)

(B) ***CKD Emission Factor.*** Operators of cement plants that generate CKD and do not recycle the CKD back to the kiln shall calculate a plant-specific CKD emission factor. The CKD emission factor shall be calculated using the CKD Emission Factor equation (EF_{CKD}) and the Plant-specific CKD Calcination Rate (d) equation specified in this section (95110(c)(1)(B).

CKD Emission Factor

$$EF_{CKD} = \frac{\dfrac{EF_{Cli}}{1+EF_{Cli}} * d}{1 - \dfrac{EF_{Cli}}{1+EF_{Cli}} * d}$$

Where:

EF_{CKD}	=	CKD Emission Factor
EF_{Cli}	=	Clinker Emission Factor
d	=	CKD Calcination Rate

Plant-specific CKD Calcination Rate

$$d = 1 - \frac{fCO_{2CKD} * (1 - fCO_{2RM})}{(1 - fCO_{2CKD}) * fCO_{2RM}}$$

Where:

fCO_{2CKD} = weight fraction of carbonate CO_2 in the CKD

fCO_{2RM} = weight fraction of carbonate CO_2 in the raw material

(2) **TOC Content in Raw Materials.** Operators of cement plants shall calculate CO_2 process emissions from the TOC content in raw materials by applying an assumed 0.2 percent organic carbon factor to the amount of raw material consumed then converting from carbon to CO_2 using the equation below.

TOC Content in Raw Materials

CO_2 emissions = $(TOC_{R.M.})$ * (R.M.) * (3.664)

Where:

$TOC_{R.M}$	=	0.2% = Organic carbon content of raw material (%)
R.M.	=	The amount of raw material consumed (metric tonnes/yr)
3.664	=	The CO_2 to carbon molar ratio

(d) **Stationary Combustion CO_2 Emissions.** Operators of cement plants shall calculate stationary combustion CO_2 emissions at cement kiln and non-kiln units separately for the quantity and type of each fuel combusted during each report year as specified in this section.

(1) Natural Gas and Associated Gas: Operators of cement plants that combust natural gas and associated gas shall calculate CO_2 emissions resulting from the combustion of natural gas and associated gas using the method provided in section 95125(c) or section 95125(d).

(2) Coal or Petroleum Coke: Operators of cement plants that combust coal or petroleum coke shall calculate CO_2 emissions using the method provided in section 95125(d). Operators of cement plants shall measure and record weekly coal consumption.

(3) Other Fossil Fuels: Operators of cement plants that combust middle distillates (such as diesel, fuel oil, or kerosene), residual oil, or LPG (such as ethane, propane, isobutene, n-Butane, or unspecified LPG) shall calculate CO_2 emissions using the method provided in section 95125(c) or section 95125(d).

(4)　Refinery Fuel Gas: Operators of cement plants that combust refinery gas, still gas, or process gas shall calculate CO_2 emissions using the method provided in section 95125(e).

(5)　Landfill Gas or Biogas: Operators of cement plants that combust landfill gas or biogas from waste water treatment shall calculate CO_2 emissions using the method provided in section 95125(c) or section 95125(d).

(6)　Biomass Solids: Operators of cement plants that combust biomass shall calculate CO_2 emissions using the method provided in section 95125(a), section 95125(c), section 95125(d) or section 95125(h)(3).

(7)　Waste-Derived Fuels: Operators of cement plants that combust waste-derived fuels including municipal solid waste shall calculate CO_2 emissions using the method provided in section 95125(c), or section 95125(d), or section 95125(h)(3).

(8)　Co-Firing of Fuels: Operators of cement plants that co-fire more than one fuel shall calculate CO_2 emissions separately for each fuel type using methods provided in sections 95125(a) and (c)-(e) as specified by fuel type in sections 95110(d)(1)-(7) and 95110(d)(9). Operators that co-fire waste-derived fuels that are partly biomass but not pure biomass with other fuels, shall determine the biomass-derived portion of total CO_2 emissions resulting from the combustion of the co-fired fuels, using the method specified in section 95125(h)(2), if applicable.

(9)　Start-Up Fuels: Operators of cement plants that primarily combust biomass-derived fuels but that combust fossil fuels for start-up, shut-down, or malfunction operating periods only, shall report CO_2 emissions from the fossil fuels using methodologies in section 95125(a) or methods specified in this section by fuel type.

(e) **Efficiency Metrics.** Cement plant operators shall calculate for the report year the CO_2 emissions generated per metric tonne of cementitious product and CO_2 emissions generated per metric tonne of clinker using the efficiency metric equations specified in this section, 95110(e).

(1)　*CO_2 Emissions per metric tonne of Cementitious Product*

$$\frac{CO_2\ \text{emissions}}{} = \frac{\text{Direct } CO_2 \text{ emissions from cement manufacturing}}{\left(\begin{array}{c}\text{Own clinker}\\\text{consumed or}\\\text{added to stock}\end{array}\right) + \left(\begin{array}{c}\text{Own clinker}\\\text{sold directly}\end{array}\right) + \left(\begin{array}{c}\text{gypsum, limestone,}\\\text{CKD \& clinker}\\\text{substitutes consumed}\\\text{for blending}\end{array}\right) + \left(\begin{array}{c}\text{cement}\\\text{substitutes}\end{array}\right)}$$

(2)   CO$_2$ Emissions per metric tonne of Clinker

$$\text{CO}_2 \text{ emissions} = \frac{\text{Direct CO}_2 \text{ emissions from cement manufacturing}}{\left(\text{Own clinker consumed or added to stock}\right) + \left(\text{own clinker sold directly}\right)}$$

NOTE: Authority cited: Sections 39600, 39601, 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 Electricity Generating Facilities, Retail Providers and Marketers.

(a) *Electricity Generating Facilities.* The operator of an electricity generating facility specified in section 95101(b) shall include the following information in the greenhouse gas emissions data report for each report year and shall meet the requirements specified in sections 95111(c)-(i) as applicable to the facility when calculating emissions for inclusion in the report.

(1)   For each facility, operators shall include:

(A)   ARB designated facility identification number (ID), nameplate generating capacity in megawatts (MW), and net power generated in the report year in megawatt hours (MWh);

(B)   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 solid fuels;

(C)   Average high heat value by fuel type, reporting in units of MMBtu per unit of fuel as specified in section 95111(a)(1)(B), if measured, based on values measured by the operator or the fuel supplier as specified in section 95125(c)(1)(A)-(C). If high heat value is not measured by the operator or available from the fuel supplier, then the operator shall report steam produced in MMBtu. The operator may elect to convert pounds of steam into MMBtu using the method provided in section 95125(h)(1)(B). The operator shall include boiler efficiency, if known;

(D)   Average carbon content, as a percent, by fuel type, if measured, based on values measured by the operator or the fuel supplier as specified in section 95125(d);

(E) CO_2, N_2O, and CH_4 emissions from stationary combustion in metric tonnes as specified in section 95111(c)-(d) by fuel type;

(F)   Process CO_2 emissions from acid gas scrubbers or acid gas reagent used in the combustion source, if applicable, in metric tonnes;

(G)   Fugitive CH_4 emissions from coal storage from coal-fired facilities, if applicable, in metric tonnes;

(H)   Fugitive emissions of HFC related to the operation of cooling units that support power generation, if applicable, in kilograms;

(I)   Fugitive CO_2 emissions from geothermal facilities, if applicable, in metric tonnes;

(J)   Fugitive SF_6, in kilograms, emitted from equipment that is located at the facility and that the operator is responsible for maintaining in proper working order. Operators of multiple facilities or operators subject to the requirements in section 95111(b)(2)(A) may aggregate SF_6 emissions for all sources or any subset of sources;

(K)   For facilities located inside California, wholesale sales (MWh) exported directly out-of-state, if known, that are additional to electricity transactions reported as specified in section 95111(b)(2)(E). Sales shall be aggregated by counterparty and measured at the busbar. The operator shall report the region of destination as Pacific Northwest (PNW) or Southwest (SW).

(2)   For each generating unit operators shall include:

(A)   Generating unit ID designated by ARB, nameplate generating capacity (MW), and net power generated (MWh);

(B)   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 solid fuels;

(C) CO_2, N_2O, and CH_4 emissions from fuel combustion in metric tonnes as specified in section 95111(c)-(d) by fuel type;

(D)   For units of facilities located inside California, wholesale sales (MWh) exported directly out-of-state by generating unit if applicable and as specified in section 95111(a)(1)(K).

(3)   **Aggregation of Multiple Units.** If a facility lacks the necessary metering or monitoring equipment to measure data individually for each generating unit, the operator may report data on an aggregated basis for multiple units that combust the same fuel type.

(4)   **Cogeneration Facilities.** Operators of generating facilities with cogeneration systems subject to the requirements of this article shall also meet the requirements of section 95112.

(5)   **Out-of-State Facilities.** Operators of out-of-state generating facilities that are not subject to any of the mandatory reporting requirements of this article may voluntarily submit a greenhouse gas emissions data report that meets applicable requirements in this article for generating facilities.

(6)   **Asset Owning/Asset Controlling Suppliers.** An asset owning or asset controlling supplier may voluntarily request that ARB assign a supplier-

specific ID to the supplier's fleet of generating facilities if the supplier's sales of renewable energy account for 50 percent or more of their total sales of electric energy for the report year or if power purchased by the supplier from unspecified sources does not exceed 20 percent of the supplier's total sales of electric energy for the report year. An asset owning or asset controlling supplier that chooses this option shall:

(A) Meet the requirements in this article as applicable for each generating facility in the supplier's fleet;

(B) Include in its greenhouse gas emissions data report the list of the generating facilities in its fleet along with the ARB designated facility ID;

(C) If wholesale power purchased by the supplier accounts for more than 10 percent of total electric energy sold by the supplier for the report year, the supplier shall include in its greenhouse gas emissions data report wholesale power purchased (MWh) from specified and unspecified sources and wholesale power sold from specified sources according to the specifications in section 95111(b)(1)(A)-(B);

(D) 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 operation control or that the supplier serves as the fleet's exclusive marketer;

(E) Provide the supplier-specific ID to retail providers who purchase unspecified power from the supplier's fleet.

(b) *Retail Providers and Marketers.*

(1) *General Requirements for Retail Providers and Marketers.* Retail providers and marketers shall meet the following general requirements in preparing their greenhouse gas emissions data report for each report year. Retail providers and marketers shall include electricity transactions associated with both renewable and nonrenewable energy sources of power.

(A) When reporting electricity transactions, retail providers and marketers shall:

1. Specify the amount of electricity in MWh;
2. For electricity from specified sources, specify the amount of electricity as measured at the busbar;

3. For electricity from unspecified sources, specify the amount of electricity as measured at the first point of receipt for which the reporting entity has information;

4. For electricity from specified sources, specify the facility name, the ARB designated facility ID, and the generating unit ID for the unit generating the power, if applicable;

5. Specify region of origin and region of destination;

6. Retail providers shall aggregate and specify electricity transactions by counterparty;

7. Marketers shall aggregate and specify electricity transactions by power supplier;

8. Specify the amount of electricity (MWh) that is null power when applicable;

9. Specify electricity received under exchange agreements as purchases and electricity delivered under exchange agreements as wholesale sales.

(B) If the region of origin for an electricity transaction cannot be documented, the retail provider or marketer shall designate the region as unknown.

(C) **Power Wheeled Through California.** When reporting power transactions involving imports into California or exports out of California, the retail provider or marketer shall exclude the amount of power imported into California that terminates in a location outside of California, as measured at the first California point of delivery.

(D) **California Department of Water Resources (DWR).** The California Department of Water Resources shall include all applicable information identified in this article for retail providers, including the amount of power used by DWR itself.

(E) **Multi-jurisdictional Retail Providers.** Multi-jurisdictional retail providers shall include information required for retail providers in this article for the service territory that includes California end-use customers.

(F) **Western Area Power Administration (WAPA).** The Western Area Power Administration shall include information required of retail providers in this article relating to serving end use California customers and reporting fugitive SF_6 emissions. In particular, WAPA shall include electricity transactions related to sources of electricity located in California that are used to serve WAPA's end-use California customers, power imported to California to serve WAPA's end-use customers including transactions from facilities owned by the Bureau of

Reclamation on the Lower Colorado River, and power exported from California.

(2) ***Greenhouse Gas Emissions Data Report: Retail Providers and Marketers.*** Retail providers and marketers shall include the following information in the greenhouse gas emissions data report for each report year. Multi-jurisdictional retail providers shall include the information in sections 95111(b)(2)(A) and 95111(b)(2)(G)-(H) but are exempt from sections 95111(b)(2)(B)-(F).

(A) Fugitive emissions of SF_6 (kg) related to transmission and distribution systems, substations, and circuit breakers located inside California that the retail provider or marketer is responsible to maintain in proper working order. SF_6 emissions shall be calculated using the methodology specified in section 95111(f).

(B) Wholesale power imported (MWh) from specified sources with final point of delivery in California and for which the retail provider or marketer was the deliverer to the first point of delivery in California, designating the region of origin as PNW or SW.

(C) Wholesale power imported (MWh) from unspecified sources with final point of delivery in California and for which the retail provider or marketer was the deliverer to the first point of delivery in California. The retail provider or marketer shall designate the region of origin as PNW, SW, or unknown and shall retain for verification purposes NERC E-tags, settlements data, or other information as confirmation of the region of origin.

(D) Retail providers shall include wholesale power imported from specified and unspecified sources with final point of delivery in California for which the retail provider is not the deliverer to the first point of delivery in California, designating the region of origin. Transactions reported under this section 95111(b)(2)(D) shall not be duplicated under section 95111(b)(3)(F).

(E) Wholesale power exported (MWh) from specified sources located inside California, and designating the region of destination (PNW, SW, or unknown).

(F) Wholesale power exported (MWh) from unspecified sources located inside California, and designating the region of destination (PNW, SW, or unknown).

(G) ***Electricity Transactions Wheeled Through California***. Wholesale power imported (MWh) into California that terminates in a location

outside of California, as measured at the first California point of delivery. The retail provider or marketer shall specify these transactions separately by the counterparty supplying power and specify the region of origin (PNW or SW). The retail provider or marketer shall retain for purposes of verification NERC E-tags, settlements data, or other information to confirm the transactions.

(H) Retail providers shall include in their greenhouse gas emissions data report for each report year the additional information listed in section 95111(b)(3).

(3) ***Greenhouse Gas Emissions Data Report: Additional Requirements for Retail Providers Only.***   Retail providers shall include the following information in the greenhouse gas emissions data report for each report year, in addition to the information identified in sections 95111(b)(1)-(2).

(A) The information listed in section 95111(a) for each generating facility over which the retail provider has operational control.

(B) The facility name, ARB designated facility ID, nameplate generating capacity (MW) and net power generated in the report year (MWh) for generating facilities over which they have operational control that are powered by nuclear, hydroelectric, wind, or solar energy.

(C) Total retail sales in megawatt hours (MWh). Multi-jurisdictional retail providers shall include total retail sales for their service territories that include California customers and the portion of total annual retail sales to California customers only.

(D) Retail sales (MWh) from specified sources that use renewable energy may be reported as a subset of total retail sales in order to reflect special retail programs to reduce greenhouse gases. Retail providers that choose to report retail sales for these programs shall aggregate sales by specified facility and include the facility name, the ARB designated ID, and a description of the program.

(E) Wholesale power purchased or power taken (MWh) from in-state specified sources.   For these transactions, the retail provider shall designate the region of origin as California.

(F) Wholesale power purchased (MWh) from unspecified sources within California or from unknown sources.   For these purchases the retail provider shall designate the region of origin as one of the following:

1.   From the CAISO real-time market;
2.   From the CAISO integrated forward market;

3. From California but other than from the CAISO markets.
4. From a region of origin that is unknown. Retail providers, other than multi-jurisdictional retail providers, shall report unspecified power purchased from an unknown region as an import under sections 95111(b)(2)(C) or section 95111(b)(2)(D), as applicable. Multi-jurisdictional retail providers shall include power purchased from an unknown region under section 95111(b)(3)(G).

(G) Multi-jurisdictional retail providers shall include wholesale power purchased or power taken from specified sources and wholesale power purchased from unspecified sources not already reported under section 95111(b)(3)(E) or section 95111(b)(3)(F)1-3, designating the region of origin as PNW, SW, or unknown, as applicable.

(H) Power purchased or taken (MWh) from a specified hydroelectric generating facility with nameplate capacity of > 30 MW (that is not a California eligible renewable resource) or from a specified nuclear facility shall be listed as one of the following:

1. Power purchased with a contract in effect prior to January 1, 2008 that remains in effect or has been renegotiated for the same facility within one year of contract expiration;
2. Power purchased not meeting the stipulation specified in section 95111(b)(3)(H)1. and that is not associated with an increase in the facility's generating capacity;
3. Power purchased not meeting the stipulation specified in section 95111(b)(3)(H)1. that is associated with an increase in the facility's generating capacity due to increased efficiencies or other capacity increasing actions;
4. Power purchased from hydroelectric generating facilities during a "spill or sell" situation where power not purchased is lost.
5. Power purchased that does not meet the stipulation specified in section 95111(b)(3)(H)1. due to federal power redistribution polices for federally owned resources and not related to price bidding.

(I) *Native Load.* The retail provider may elect to designate the power taken from a generating facility partially or fully owned, or operated by the retail provider and power purchased or taken from other specified sources as serving native load if the facility meets one of the following criteria and shall state which of the criteria were met:

1. The generating facility is a California eligible renewable resource and, prior to the reporting date, the reporting entity has retired the WREGIS or NVTREC certificates associated with the power received from the facility during the report year.

2. The generating facility is a hydroelectric generation facility.
3. The generating facility is partially or fully owned by the retail provider, operated by the retail provider, or under a long term power contract. If a facility is designated as serving native load on this basis, all generating facilities from which the retail provider purchases or takes specified power that run at the same or greater average annual capacity factor shall also be designated as serving native load.
4. The generating facility is a qualifying facility whose generation the reporting entity purchases under a power contract.

(J) Retail providers shall designate a wholesale sale as inside California if the point of delivery of the sale is within California. If retail providers cannot provide documentation that the point of delivery of the sale is within California, then retail providers, not multi-jurisdictional, shall report the wholesale sale as an export under section 95111(b)(2)(E) or section 95111(b)(2)(F), as applicable, and multi-jurisdictional retail providers shall include the sale under section 95111(b)(3)(O).

(K) Wholesale sales (MWh) of power purchased or taken from specified facilities operated by the retail provider delivered to point of delivery inside California and the designation of the region of destination as CAISO real-time market, CAISO integrated forward market, or California.

(L) Wholesale sales (MWh) of power purchased or taken from specified sources not operated by the retail provider delivered to point of delivery inside California and the designation of the region of destination as CAISO real-time market, CAISO integrated forward market, or California.

(M) Wholesale sales (MWh) of power purchased from unspecified sources delivered to counterparties inside California and the designation of the region of destination as CAISO real-time market, CAISO integrated forward market, or California.

(N) Multi-jurisdictional retail providers shall indicate those wholesale sales included in section 95111(b)(3)(K)-(M) for which they are the deliverer to the first point of delivery in California (not located within their own service territory.)

(O) Multi-jurisdictional retail providers shall include wholesale sales (MWh) of power purchased or taken from specified or unspecified sources not already reported in section 95111(b)(3)(K)-(N).

(P)   If the retail provider holds a contract that entitles the retail provider to a specified percentage of a facility's generation in the report year, the retail provider shall include power purchased or sold from that facility as being from a partially owned facility.

(Q)   For facilities fully or partially owned by the retail provider, include facility name, ARB designated facility ID, generating unit ID as applicable, percent ownership share at the facility level, ownership share at the generating unit level as applicable, and net power generated in the report year (MWh) if not already reported under section 95111(a).

(R)   For facilities that are fully or partially owned by the retail provider and that have CO_2 emissions greater than 1,100 lbs of CO_2 per MWh based on the most recent greenhouse gas emissions data report that received a positive verification opinion or on CO_2 emissions reported to U.S.EPA under 40 CFR Part 75, the retail provider may elect to include:

   1.   Wholesale sales (MWh) made by the retail provider or on behalf of the retail provider from the facility or unit to counterparties located outside California where:
      i.   The power could not be delivered to the reporting entity during the hours in which it was sold due to congestion in the transmission and distribution system or similar issues or;
      ii. The retail provider did not need the power during the hours in which it was sold for reasons not related to reducing the retail provider's greenhouse gas emissions responsibility. Reasons may include, but are not limited to, the retail provider's own load was met by resources that were less expensive than the specified facility (excluding any value associated with greenhouse gas mitigation).

   2.   Amount of power generation that was reduced from the facility or unit in MWh per year as a result of the reduced demand for power by the retail provider. The retail provider shall retain documentation that associates reduced generation with reduced demand.

(S)   The retail provider may elect to separately report retail sales related to the electrification of shipping ports, truck stops, and motor vehicles if metering is available to separately track these sales from other retail sales.

(c) *Calculation of CO$_2$ Emissions from Stationary Combustion*. Operators of generating facilities shall meet the following requirements in preparing CO_2

emission calculations from stationary combustion for inclusion in the greenhouse gas emissions data report.

(1) **Natural Gas.** Operators of generating facilities or units that combust natural gas and are subject to the requirements of 40 CFR Part 75 shall include Part 75 CO_2 emissions data for the report year. Operators may elect to use revenue fuel meters to conduct quality checks on generating unit level information. For facilities or units that combust natural gas but are not required to report CO_2 emissions under 40 CFR Part 75, the operator shall calculate and include CO_2 emissions using methodologies provided in:

   (A) Sections 95125(c)-(d) or (g) if the high heat value is $\geq$ 975 and $\leq$ 1100 Btu per scf or;

   (B) Section 95125(d) or (g) if the high heat value is < 975 or > 1100 Btu per scf.

(2) **Coal or Petroleum Coke.**

   (A) Operators of generating facilities or units that combust coal or petroleum coke and are subject to the requirements of 40 CFR Part 75 shall include Part 75 CO_2 emissions data for the report year, or CO_2 emissions based on alternative equations and specifications by fuel type provided in 40 CFR Part 75, Appendix G;

   (B) If the generating facility or unit is not subject to the requirements in 40 CFR Part 75, the operator of the generating facility shall calculate and include CO_2 emissions using methods specified in section 95125(d) or section 95125(g).

(3) **Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases (LPG).**

   (A) If a generating facility or unit combusts middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-Butane, or unspecified LPG) and is subject to the requirements of 40 CFR Part 75, the operator of the facility shall include Part 75 CO_2 emissions data for the report year;

   (B)   If the generating facility or unit is not subject to the requirements of 40 CFR Part 75, the operator shall calculate and include annual CO_2 emissions using the methods specified in sections 95125(c)-(d) or (g).

(4) **Refinery Fuel Gas, Flexigas, or Associated Gas.** If a generating facility combusts refinery fuel gas, flexigas, or associated gas, the operator shall

calculate and include CO_2 emissions for the report year using the methods specified by fuel type in sections 95113(a)(1)(A)-(C) or 95113(a)(1)(E).

(5) **_Landfill Gas or Biogas._** If a facility combusts landfill gas or biogas derived from biomass, the operator shall calculate and include CO_2 emissions for the report year using the method specified in section 95125(c), 95125(d), or 95125(g).

(6) **_Biomass Solids or Municipal Solid Waste._**

(A) If a facility combusts biomass solids or municipal solid waste, the operator shall calculate and include CO_2 emissions for the report year using methodologies provided in section 95125(g) based on continuous emission monitoring systems, CO_2 concentrations, and flue gas flow rates;

(B) If the facility combusts municipal solid waste and does not have appropriate devices to measure CO_2 concentrations and flue gas flow rates, the operator shall use methods specified in section 95125(h);

(C) If the facility combusts biomass solids and does not have appropriate devices to measure CO_2 concentrations and flue gas flow rates, the operator shall use a method specified in sections 95125 (c)-(d) or (g)-(h).

(7) **_CO_2 Emissions for Fuels Co-Fired._** Operators shall use the following methodologies to determine separately and include CO_2 emissions from fuels (excluding refinery gases) that are co-fired at a facility.

(A) If more than one fossil fuel and only fossil fuels are co-fired in a facility that does not report using data from a continuous emissions monitoring system, then the operator shall calculate CO_2 emissions separately for each fuel type using methods provided in sections 95125(c)-(e) as specified by fuel type in sections 95111(c)(1)-(4). Operators who have the option in this article to calculate emissions based on data from a continuous emissions monitoring system, and who co-fire more than one fossil fuel, need not report emissions separately for each fossil fuel.

(B) If a biomass-derived fuel is co-fired with a fossil fuel in a facility and the operator does not report CO2 emissions using data from a continuous emissions monitoring system, then the operator shall calculate CO2 emissions separately for each fuel type using methods provided in sections 95125(a), (c), (d) or (e) as specified by fuel type in sections 95111(c)(1)-(6) and (8). If the facility does have a continuous emissions monitoring system, then the operator shall calculate

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emissions associated with each fuel using the methods specified in section 95125(g)(4).

(8) **Start-Up Fuels.** The operators of generating facilities that primarily combust biomass-derived fuels but that combust fossil fuels for start-up, shut-down, or malfunction operating periods only, shall calculate and include CO_2 emissions from fossil fuel combustion using the method provided in section 95125(a) or methods provided in sections 95125(c)-(e).

(d) **Calculation of N_2O and CH_4 from Stationary Combustion.** Operators of generating facilities shall use the methodologies provided in section 95125(b) to calculate and include N_2O and CH_4 emissions from stationary combustion.

(e) **Calculation of CO_2 Process Emissions from Acid Gas Scrubbing.** Operators that use acid gas scrubbers or add an acid gas reagent to the combustion source shall include CO_2 emissions from these processes if these emissions are not already captured in CO_2 emissions calculations based on a continuous emissions monitoring system. The operator shall calculate CO_2 emissions from the acid gas processes using the following equation:

$$CO_2 = S * R * (CO_{2\ MW} / Sorbent_{MW})$$

Where:
CO_2 = CO_2 emitted from sorbent for the report year, metric tonnes;
S = Limestone or other sorbent used in the report year, metric tonnes;
R = Ratio of moles of CO_2 released upon capture of one mole of acid gas;
$CO_{2\ MW}$ = molecular weight of carbon dioxide (44);
$Sorbent_{MW}$ = molecular weight of sorbent (if calcium carbonate, 100).

(f) **Determining Fugitive SF_6 Emissions.** Operators of generating facilities, retail providers, and marketers shall use the methodology provided by the U.S. EPA SF_6 Emission Reduction Partnership for Electric Power Systems to determine fugitive SF_6 emissions as specified in Appendix A. The operator shall convert pounds of SF_6 into kilograms.

(g) **Determining Fugitive HFC Emissions.** Operators of generating facilities shall calculate fugitive HFC emissions separately for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using the methodology provided by U.S. EPA SF_6 Emission Reduction Partnership but substituting HFCs for SF_6 in the methodology. The operator shall convert pounds of HFCs into kilograms. This section does not apply to air or water cooling systems or condensers that do not contain HFCs.

(1) Operators who are reporting by individual cooling unit may elect to use service logs to document HFC usage and emissions. Service logs should

document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The operator may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The operator shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:
$HFC_{Install}$ = HFC emitted during initial charging/installation of the unit, kilograms;

$HFC_{Service}$ = HFC emitted during use and servicing of the unit for the report year, kilograms;

HFC_{Retire} = HFC emitted during the removal from service/retirement of the unit, kilograms;

R_{new} = HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kilograms;

C_{new} = Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kilograms;

$R_{recharge}$ = HFC used to recharge the unit during maintenance and service, kilograms;

$R_{recover}$ = HFC recovered from the unit during maintenance and service, kilograms;

C_{retire} = Nameplate capacity of the retired unit, kilograms;

R_{retire} = HFC recovered from the retired unit, kilograms.

(h) **Calculation of Fugitive CH_4 Emissions.** Operators of generating facilities that combust coal shall calculate and include fugitive CH_4 emissions from coal storage using the methodology provided in section 95125(j).

(i) **Calculation of Fugitive CO_2 Emissions from Geothermal Generating Facilities.** Operators of geothermal electricity generating facilities shall calculate and include fugitive CO_2 emissions using one of the following methods:

(1) $CO_2 = EF * Heat * (0.001)$

Where
CO_2 = CO_2 emissions, metric tonnes per year;

EF = Default fugitive CO_2 emission factor for geothermal facilities as specified in Appendix A, kg per MMBtu;

Heat = Heat taken from geothermal steam and/or fluid, MMBtu per year.

(2) Operators of geothermal generating facilities may elect to calculate CO_2 emissions using ARB approved source specific emission factors derived from tests conducted at least annually under the supervision of ARB or the local air pollution control district or air quality management district. Upon approval of a test plan by ARB, the test procedures in that plan shall be repeated in future years to update the source specific emission factors annually. In the absence of source specific emission factors approved by ARB, the operator shall use the method specified above in section 95111(i)(1).

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

§ 95112. Data Requirements and Calculation Methods for Cogeneration Facilities.

(a) ***Greenhouse Gas Emissions Data Report.*** The operator of a cogeneration facility specified in section 95101(b) shall include the following information in the greenhouse gas emissions data report for each report year. The operator of a cogeneration facility that is a self-generation facility with nameplate generating capacity less than ten megawatts and is not otherwise subject to the requirements of this article as specified in Section 95101(b)(1)-(6) and (8), may elect to submit an abbreviated emissions data report as specified in Section 95112(c).

(1) Facility level and generating unit information as specified in sections 95111(a)(1)-(3) as applicable.

(2) Cogeneration System:
   (A) Prime mover of each cogeneration system.
   (B) Identification of the cogeneration facility as a topping cycle or bottoming cycle plant
   (C) Description of waste heat technology, including nameplate data for waste heat boiler, waste heat jacket heat exchanger, absorption chiller, and hot water heat exchanger

(3) Electricity Generation:
   (A) Electricity sold wholesale (MWh)
   (B) Electricity sold or provided directly to end-users (MWh) and end-user's NAICS code
   (C) Electricity consumed on-site for each report year (MWh)
   (D) Efficiency of electricity generation, if known

(4) Thermal Energy Production:
   (A) Total useful thermal output (MMBtu)
      1. Amount of thermal energy sold or provided to cogeneration thermal host (MMBtu) and customer's NAICS code
      2. Amount of thermal energy from the cogeneration system consumed on-site for processes other than the cogeneration system for each report year (MMBtu)
   (B) Input steam to steam turbine, if measured (MMBtu)
   (C) Output of heat recovery steam generator (MMBtu)
   (D) Fuel fired for supplemental firing in the duct burner of the heat recovery steam generator (MMBtu)
   (E) Efficiency of thermal energy production, if known

(5) Distributed Emissions:
   (A) Distributed emissions to thermal energy production (metric tonnes CO_2)

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(B) Distributed emissions to electricity generation (metric tonnes CO_2)

(C) Distributed emissions to manufactured product outputs, as applicable (metric tonnes CO_2)

(6) Indirect electricity usage as specified in section 95125(k).

(A) Electricity purchased and consumed (kWh)

(B) Electricity provider (Name)

(b) ***Calculation of CO_2, N_2O, and CH_4 Emissions.*** Operators of cogeneration facilities shall calculate and report emissions for each source specified in this section.

(1) CO_2 emissions from stationary combustion using methodologies listed by fuel type for electricity generating facilities as specified in section 95111(c).

(2) GHG emissions from processes and from fugitive sources as specified for electricity generating facilities in sections 95111(e)-(h), if applicable, using the methodologies designated in the respective sections.

(3) N_2O and CH_4 emissions from stationary combustion using the methodologies provided in section 95125(b).

(4) **Distributed Emissions.** Topping cycle plant operators shall calculate distributed emissions for electricity generation and thermal energy production separately using the Efficiency Method provided in section 95112(b)(4)(A). Bottoming cycle plant operators shall calculate distributed emissions for electricity generation, thermal energy production, and manufactured product outputs using the Detailed Efficiency Method provided in section 95112(b)(4)(B).

(A) Distributed Emissions for Topping Cycle Plants: Operators shall calculate distributed emissions using the Efficiency Method equations specified in this section, 95112(b)(4)(A). Operators shall distribute emissions to electricity generation by subtracting distributed emissions to thermal energy production from emissions from stationary combustion for the report year. Operators shall calculate emissions using a facility-specific electricity generation efficiency value as specified in section 95112(b)(4)(A)1, if parameters are known. Operators shall use the Heat Recovery Steam Generator (HRSG) or boiler manufacturer's rating for the thermal energy production efficiency value, if known. Operators may use assumed values of 0.35 for electricity generation efficiency and/or 0.80 for thermal energy production efficiency, when parameters are unknown.

Efficiency Method

Thermal Energy Production　　　　　　　　　*Electricity Generation*

$$E_H = \frac{H/e_H}{H/e_H + P/e_P} * E_T$$　　　　　　$$E_P = E_T - E_H$$

Where:

E_H　=　Distributed emissions to thermal energy production, metric tonnes CO_2

H　=　Total useful thermal output for the report year, MMBtu

e_H　=　Efficiency of thermal energy production

P　=　Power generated for the report year, MMBtu (MWh x 3.413) = MMBtu

e_P　=　Efficiency of electricity generation

E_T　=　CO_2 emissions from stationary combustion in the report year, metric tonnes CO_2

E_P　=　Distributed emissions to electricity generation, metric tonnes CO_2

1.　*Facility-Specific Electricity Generation Efficiency Value:*

$$e_P = \frac{P}{F}$$

Where:

e_P　=　Efficiency of electricity generation

P　=　Power generated for the report year, MMBtu

F　=　Total fuel input, MMBtu

(B)　Distributed Emissions for Bottoming Cycle Plants: Operators shall calculate distributed emissions using the Detailed Efficiency Method equations specified in this section, 95112(b)(4)(B). Operators shall distribute emissions to electricity generation by subtracting distributed emissions to thermal energy production and manufactured product from stationary combustion emissions for the report year. Bottoming cycle plant operators shall calculate stationary combustion emissions for the manufacturing process as specified in section 95112(b)(4)(B)2. Operators shall report emissions using a calculated facility-specific electricity generation efficiency value as specified in section 95112(b)(4)(B)1, if parameters are known. Operators shall use the Heat Recovery Steam Generator (HRSG) or boiler manufacturer's rating for the thermal energy production efficiency value, if known. Operators may use assumed values of 0.35 for electricity generation efficiency and/or 0.80 for thermal energy production efficiency, when parameters are unknown.

Detailed Efficiency Method

Thermal Energy Production	*Electricity Generation*

$$E_H = \frac{H/e_H}{H/e_H + P/e_P} * (E_T - E_M) \qquad E_P = E_T - E_H - E_M$$

Where:

E_H = Distributed emissions to thermal energy production, metric tonnes CO_2

H = Total useful thermal output for the report year, MMBtu

e_H = Efficiency of thermal energy production

P = Power generated for the report year, MMBtu
(MWh * 3.413) = MMBtu

e_P = Efficiency of electricity generation

E_T = CO_2 emissions from stationary combustion in the report year, metric tonnes

E_M = Distributed emissions to manufacturing product, metric tonnes CO_2, computed as specified in section 95112(b)(4)(B)2.

E_P = Distributed emissions to electricity generation, metric tonnes CO_2

1. *Facility-Specific Electricity Generation Efficiency Value:*

$$e_P = \frac{P}{(H_{ST})}$$

Where:

e_P = Efficiency of electricity generation

P = Power generated for the report year, MMBtu

H_{ST} = Input steam to steam turbine, MMBtu.

2. *Emissions Assigned to Manufacturing Process:*

$$E_M = E_T \left[1 - \frac{P + H + F_S * (1 - e_H)}{F + H_e} \right]$$

Where:

E_M = Distributed emissions to manufacturing product, metric tonnes CO_2

E_T = Emissions from stationary combustion in the report year, metric tonnes CO_2

P = Power generated for the report year, MMBtu
(MWh * 3.413) = MMBtu

H = Total useful thermal output for the report year, MMBtu

F = Total fuel input, MMBtu

F_S = Fuel fired for supplemental firing in the duct burner of the HRSG, MMBtu

H_e = Exothermic heat from manufacturing process, MMBtu, computed as specified in section 95112(b)(4)(B)3.

e_H = Efficiency of thermal energy production

H_e shall only be included if an exothermic manufacturing process is used.

3. *Exothermic Heat from Manufacturing Process*

$$H_e = \frac{HRSG}{e_H} - F$$

Where:

H_e = Exothermic heat from manufacturing process, MMBtu

HRSG = Output of heat recovery steam generator in the report year, MMBtu

e_H = Efficiency of thermal energy production

F = Total fuel input, MMBtu

If H_e value calculated above is negative, then the exothermic heat of the process is not sufficient to overcome the process use and/or loss of the input fuel heat, and the H_e value is set to 0.

(c) ***Abbreviated Greenhouse Gas Emissions Data Report.*** The operator of a cogeneration facility that is a self-generation facility with nameplate generating capacity <10 MW and is not otherwise subject to the requirements of this article as specified in Section 95101(b)(1)–(6) and (8), and who elects to submit an abbreviated emissions data report, shall include the following information for each report year.

(1) At the facility level, operators shall include:

(A) ARB designated facility identification number (ID), nameplate generating capacity in megawatts (MW), and net power generated in the report year in megawatt hours (MWh);

(B) Total fuel consumption by fuel type for each cogeneration system 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 solid fuels;

(C) Cogeneration system information as specified in section 95112 (a)(2);

(D) Electricity generation information as specified in section 95112 (a)(3);

(E) CO_2, N_2O, and CH_4 emissions from stationary combustion associated with the facility's cogeneration system in metric tonnes, calculated as specified in section 95112(d);

    1. CO_2 emissions from biomass-derived fuels (metric tonnes)

(2) For each generating unit operators shall include:

(A) Generating unit ID designated by ARB, nameplate generating capacity (MW), and net power generated (MWh);

(B) Fuel consumption by fuel type, where generating units of the same fuel type are separately metered;

(C) CO_2, N_2O, and CH_4 emissions from fuel combustion in metric tonnes as specified in section 95112(d), where generating units of the same fuel type are separately metered.

(3) Operators may elect to submit any of the additional information required in section 95112(a).

(d) ***Calculation of CO_2, N_2O, and CH_4 Emissions.*** The operator of a cogeneration facility that files an abbreviated emissions data report as specified in section 95112(c) shall calculate emissions for each source specified in this section:

(1) CO_2 emissions from stationary combustion using the methodologies provided in either (A), (B), or (C) below.

(A) Use of continuous emissions monitoring systems (CEMS) as specified in section 95125(g);

(B) Use of default emission factors as specified in section 95125(a);

(C) Use of fuel heat content, carbon content or other fuel-specific parameters as specified in section 95125(c), (d), or (h).

(2) N_2O and CH_4 emissions from stationary combustion using the methodologies provided in section 95125(b).

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

§ 95113. Data Requirements and Calculation Methods for Petroleum Refineries.

(a) *Greenhouse Gas Emissions Data Report.* The operator of a petroleum refinery specified in section 95101(b) shall include in the emissions data report for each report year the information required by this section, using the calculation methods specified.

   (1) *Stationary Combustion – CO_2 Emissions.*
        The operator may elect to determine CO_2 combustion emissions using Continuous Emissions Monitoring Systems (CEMS) as specified in section 95125(g) (metric tonnes). In the absence of such CEMS data the operator shall use the following methods by fuel type.

       (A) Refinery Fuel Gas: CO_2 emissions resulting from the combustion of refinery fuel gas as specified in section 95125(d) or 95125(e), (metric tonnes).

       (B) Natural Gas and Associated Gas: CO_2 emissions resulting from the combustion of natural gas and associated gas as specified in section 95125(c) or 95125(d), (metric tonnes).

       (C) Fuel Mixtures: CO_2 emissions resulting from the combustion of each fuel contained in the fuel mixture or for each fuel mixture as specified in section 95125(f), (metric tonnes).

       (D) Other Fuels: CO_2 emissions resulting from the combustion of No. 1, No. 2, No 4, No. 5, and No. 6 fuels, kerosene, residual oil, distillate oil, gasoline, diesel fuel, and LPG using the methods specified in section 95125(a), 95125(c), or 95125(d), (metric tonnes).

       (E) Low Btu gases: CO_2 emissions resulting from the combustion and/or destruction of low Btu gases as specified in section 95125(f) or 95113(d)(3). CO_2 emissions resulting from the combustion of flexigas as specified in section 95125(d)(3)(A), (metric tonnes).

   (2) *Stationary Combustion – CH_4 and N_2O.* Emissions from stationary combustion sources using methods specified in section 95125(b), (metric tonnes).

   (3) *Fuel and Feedstock Consumption.* Fuel consumption and feedstock consumption used to calculate GHG emissions by type in the report year (including petroleum coke) 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 solid fuels.

(4) **Hydrogen Production Plant Emissions.** The operator shall calculate emissions using the methodologies specified in section 95114, (metric tonnes).

(5) **Process Emissions.** The operator shall calculate process emissions using the methodologies in section 95113(b), (metric tonnes), and shall report any CO_2 molecular fractions derived from approved source tests as specified in section 95113(b)(5)(B) .

(6) **Fugitive Emissions.** The operator shall calculate fugitive emissions using the methods specified in section 95113(c), (metric tonnes).

(7) **Flaring Emissions.** The operator shall calculate flare and control device emissions using the methods specified in section 95113(d), (metric tonnes)

(8) **Electricity Generating Units.** Operators of refineries with electricity generating units subject to the requirements of this article shall meet the requirements of section 95111.

(9) **Cogeneration Emissions.** Operators of refineries with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(10) **Indirect Energy Purchases.** The operator shall calculate indirect energy purchased and consumed using methods specified in section 95125(k)-(l).

(b) **Calculation of Process Emissions.** The operator shall calculate process emissions as specified in this section. Operators may elect to calculate CO_2 process emissions resulting from catalyst regeneration (sections 95113(b)(1) and 95113(b)(2)) using a continuous emission monitoring system as specified in section 95125(g). In the absence of such CEMS data the operator shall use the following methods.

(1) Catalytic Cracking

   (A) The operator shall calculate and report CO_2 emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using the methods specified in sections 95113(b)(1). Hourly coke burn rate shall be calculated as shown below:

$$CR = K_1 Q_r (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r [\%CO/2 + \%CO_2 + \%O_2] + K_3 Q_{oxy} (\%O_{xy})$$

   Where:
   CR = hourly coke burn rate (kg/hr or lb/hr)
   K_1, K_2, K_3 = material balance and conversion factors (K_1, K_2, and K_3 - see Table 11, Appendix A)

Q_r = volumetric flow rate of exhaust gas before entering the emission control system (dscm/min or dscf/min)

Q_a = volumetric flow rate of air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)

$\%CO_2$ = percent CO_2 concentration in regenerator exhaust, percent by volume – dry basis

$\%CO$ = percent CO concentration in regenerator exhaust, percent by volume – dry basis

$\%O_2$ = percent oxygen concentration in regenerator exhaust, percent by volume – dry basis

Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from control room instrumentation (dscm/min or dscf/min)

$\%O_{xy}$ = O_2 concentration in O_2 enriched air stream inlet to regenerator, percent by volume – dry basis

Q_r shall be determined in the following manner:

$$Q_r = (79 * Q_a + (100- \%Q_{xy}) * Q_{oxy})/(100 - \%CO_2 - \%CO - \%O_2)$$

Where:

Q_r = volumetric flow rate of exhaust gas from regenerator before entering the emission control system (dscm/min or dscf/min)

Q_a = volumetric flow rate of air to regenerator, as determined from control room instrumentation (dscm/min or dscf/min)

$\%Q_{xy}$ = oxygen concentration in oxygen enriched air stream, percent by volume – dry basis

Q_{oxy} = volumetric flow rate of O_2 enriched air to regenerator as determined from catalytic cracking unit control room instrumentation (dscm/min or dscf/min)

$\%CO_2$ = carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis

$\%CO$ = carbon monoxide concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume $\%CO$ to be zero

$\%O_2$ = O_2 concentration in regenerator exhaust, percent by volume – dry basis

(B) The operator shall calculate a daily average coke burn rate (CR_d) for each day of operation as the sum of hourly coke burn rate determinations for each hour of operation divided by the number of operational hours per day. CR_d (lb/day) shall be converted to (kg/day).

(C) The operator shall calculate and report CO_2 emissions as shown below:

$$CO_2 = \sum_{1}^{n} CR_d * CF * 3.664 * 0.001$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)

n = number of days of operation in the report year

CR_d = daily average coke burn rate (kg/day)

CF = carbon fraction in coke burned

3.664 = conversion factor – carbon to carbon dioxide

0.001 = conversion factor – kg to metric tonnes

(2) Other Catalyst Regeneration

(A) The operator shall calculate and report process CO_2 emissions resulting from periodic catalyst regeneration as shown below.

$$CO_2 = \sum_{1}^{n} CRR * (CF_{spent} - CF_{regen}) * 3.664 * 0.001$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)

CRR = mass of catalyst regenerated (mass/regeneration cycle)

CF_{spent} = weight fraction carbon on spent catalyst

CF_{regen} = weight fraction carbon on regenerated catalyst (default = 0)

n = number of regeneration cycles

3.664 = conversion factor – carbon to carbon dioxide

0.001 = conversion factor – kg to metric tonnes

(B) The operator shall calculate and report process CO_2 emissions resulting from continuous catalyst regeneration in operations other than FCCU and fluid cokers (e.g. catalytic reforming) as shown below.

$$CO_2 = CC_{irc} * (CF_{spent} - CF_{regen}) * H * 3.664$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)

CC_{irc} = average catalyst regeneration rate (tonnes/hr)

CF_{spent} = weight carbon fraction on spent catalyst

CF_{regen} = weight carbon fraction on regenerated catalyst (default = 0)

H = hours regenerator was operational (hr/yr)

3.664 = conversion factor – carbon to carbon dioxide

(3) Process Vents

(A) The operator shall calculate and report process emissions of CO_2, CH_4, and N_2O from process vents using the method shown below. Process emissions calculated and reported using other methods specified in this regulation shall not be calculated and reported here.

$$E_x = \sum_{1}^{n} VR * F_x * MW_x/MVC * VT * 0.001$$

Where:

E_x = emissions of x (metric tonnes/yr)
(x = CO_2, N_2O, CH_4)
VR = vent rate (scf/unit time)
F_x = molar fraction of x in vent gas stream
MW_x = molecular weight of x (kg/kg-mole)
MVC = molar volume conversion (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole for STP of 60°F, and 1 atmosphere)
VT = time duration of venting
n = number of venting events
0.001 = conversion factor – kg to metric tonnes

(4) Asphalt Production

(A) The operator shall calculate and report CO_2 and CH_4 emissions resulting from asphalt blowing activities (where these emissions are not reported to the local AQMD/APCD and subsequently reported as directed in section 95113(d)) using the method specified below:

$$CH_4 = (M_A * EF * MW_{CH4}/MVC)(1 – DE) * 0.001$$

Where:

CH_4 = CH_4 emissions (metric tonnes/yr)
M_A = mass of asphalt blown (10^3 bbl/yr)
EF = emission factor (EF = 2,555 scf $CH_4/10^3$ bbl)
MW_{CH4} = CH_4 molecular weight (16.04 kg/kg-mole)
MVC = molar volume conversion factor (849.5 scf/kg-mole, for STP of 20°C and 1 atmosphere)
DE = control measure destruction efficiency (DE = 98% expressed as 0.98)
0.001 = conversion factor – kg to metric tonnes

$$CO_2 = (M_A * EF * MW_{CH4}/MVC) * DE * 2.743 * 0.001$$

Where:

CO_2 = CO_2 emissions (metric tonnes/yr)
M_A = mass of asphalt blown (10^3 bbl/yr)
EF = emission factor (EF = 2,555 scf CH_4/10^3 bbl)
MW_{CH4} = CH_4 molecular weight (16.04 kg/kg-mole)
MVC = molar volume conversion factor (849.5 scf/kg mole, for STP of 20℃ and 1 atmosphere)
DE = control measure destruction efficiency (DE = 98% expressed as 0.98)
2.743 = CH_4 to CO_2 conversion factor
0.001 = conversion factor – kg to metric tonnes

(5)   Sulfur Recovery

(A)   The Operator shall calculate and report CO_2 process emissions from sulfur recovery units (SRU) using the methods specified below:

$$CO_2 = FR * MW_{CO2}/MVC * MF * 0.001$$

Where:

CO_2 = emissions of CO_2 (metric tonnes/yr)
FR = volumetric flow rate of acid gas to SRU (scf/year)
MW_{CO2} = molecular weight of CO_2 (44 kg/kg-mole)
MVC = molar volume conversion (849.5 scf/ kg-mole, for STP of 20℃ and 1 atmosphere or 836 scf/kg-mole, fo r STP of 60℉, and 1 atmosphere)
MF = molecular fraction (%) of CO_2 in sour gas (default MF = 20% expressed as 0.20)
0.001 = conversion factor – kg to metric tonnes

(B)   As an alternative to using the default MF value, the operator may elect to calculate CO_2 emissions using an ARB approved, source specific molecular fraction of CO_2 in the sour gas, derived from source tests conducted at least once per calendar year under the supervision of ARB or the local air pollution control district or air quality management district. Upon approval of a source test plan by ARB, the source test procedures in that plan shall be repeated in subsequent years to update the source specific CO_2 molecular fractions annually. In the absence of source specific CO_2 molecular fractions approved by ARB, the operator shall use the default value provided in section 95113(b)(5)(A).

(c) **_Calculation of Fugitive Emissions._** The operator shall calculate and report fugitive emissions as specified below.

(1) Wastewater Treatment – CH_4 and N_2O

(A) The operator shall calculate and report methane emissions from wastewater treatment as shown below:

$$CH_4 = [(Q * COD_{qave}) - S] * B * MCF * 0.001$$

Where:
CH_4 = emission of methane (tonnes/yr)
Q = volume of wastewater treated (m^3/yr)
COD_{qave} = average of quarterly determinations of chemical oxygen demand of the wastewater (kg/m^3)
S = organic component removed as sludge (kg COD/yr)
B = methane generation capacity ($B = 0.25$ kg CH_4/kg COD)
MCF = methane conversion factor for anaerobic decay (0-1.0) consult Table 12 in Appendix A
0.001 = conversion factor – kg to metric tonnes

(B) The operator shall calculate and report nitrous oxide emissions from wastewater treatment as shown below:

$$N_2O = Q * N_{qave} * EF_{N2O} * 1.571 * 0.001$$

Where:
N_2O = emissions of N_2O (metric tonnes/yr)
Q = volume of wastewater treated (m^3/yr)
N_{qave} = average of quarterly determinations of N in effluent (kg N/m^3)
EF_{N2O} = emission factor for N_2O from discharged wastewater (0.005 kg N_2O-N/kg N)
1.571 = conversion factor – kg N_2O-N to kg N_2O
0.001 = conversion factor – kg to metric tonnes

(2) Oil-Water Separators – The operator shall calculate and report emissions from oil-water separators as shown below.

$$CH_4 = EF_{sep} * V_{water} * CF_{NMHC} * 0.001$$

Where:
CH_4 = emission of methane (tonnes/yr)
EF_{sep} = NMHC (non methane hydrocarbon) emission factor (kg/m^3) see Table 13 in Appendix A.
V_{water} = volume of waste water treated by the separator (m^3/yr)

CF_{NMHC} = NMHC to CH_4 conversion factor (CF_{NMHC} = 0.6)
0.001 = conversion factor – kg to metric tonnes

(3) Storage Tanks

(A) The operator shall calculate and report CH_4 emissions from crude oil, naphtha, distillate oil, asphalt, and gas oil storage tanks using the U.S. EPA TANKS Model (Version 4.09D). VOC emission values generated by the model shall be converted to methane emissions using a default conversion factor of 0.6 (CH_4 = 0.6 * VOC). Alternatively, operators may determine species specific conversion factors determined by storage tank headspace vapor analysis using ARB approved sampling and analysis methodology.

(4) Equipment Fugitive Emissions

(A) The operator shall calculate and report CH_4 fugitive emissions for all gas service components as specified in CAPCOA (1999) Method 3: Correlation Equation Method in the following manner:

1. Components shall be identified as one of the following classification types: valve, pump seal, other, connector, flange, open-ended line. Operators shall use the Component Identification and Counting Methodology and screening methods found in CAPCOA (1999), which is incorporated by reference herein.

2. Screening values (SV) for each component comprising all natural gas, refinery fuel gas, and PSA off-gas systems shall be measured and recorded using instrumentation capable of detecting methane. Operators shall conduct screenings at the frequency interval required by their local air district.

3. Operators shall calculate VOC emissions in the following manner:

a. Zero Components – Use of Default Zero Factor. For zero components (components where the SV, corrected for background, equals 0.0 ppmv – i.e., the SV is indistinguishable from zero) for each screening period (e.g. month, quarter, year), operators shall calculate VOC emissions as follows:

$$E_{VOC-0} = \sum_{i=1}^{6} CC_i * ZF_{i0} * t$$

Where:

E_{VOC-0} = zero component VOC emission (kg/screening period)

i = component type (1 = valve, 2 = pump seal, 3 = other, 4 = connector, 5 = flange, 6 = open-ended line)
CC_i = number of i components where SV = 0
ZF_{i0} = zero VOC emission factor (kg/hr) for component i (see Appendix A, Table 14)
t = time (hours) since last screening

b. Leaking Components – Use of Correlation Equation. Operators shall choose one of the following emission calculation pathways for leaking components based on local air district rules applicable at the facility.

For facilities located in air districts which authorize the use of correlation equations for screening values between background and 9,999 ppmv, the operator shall use the following method for these components and the pegged component method found in section 95113(c)(4)(A)(3)(c) for components pegged over 9,999 ppmv.

For facilities located in air districts which authorize the use of correlation equations for screening values between background and 99,999 ppmv, the operator shall use the following method for these components and the pegged component method found in section 95113(c)(4)(A)(3)(d) for components pegged over 99,999 ppmv.

$$E_{VOCL-C} = \sum_{i=1}^{6} \sum_{n=1}^{n} (\sigma_i * SV_n^{\beta i}) * t$$

Where:
E_{VOCL-C} = leaking components VOC emissions (kg/screening period)
i = component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open ended-line)
n = number of i components
σ_i = correlation equation coefficient for component type i (see Appendix A, Table 14)
SV_n = screening value for component n
βi = correlation equation exponent for component type i (see Appendix A, Table 14)
t = time (hours) component has been leaking – default value is time from last screening

c. Pegged components over SV 9,999 ppmv. The operator shall calculate VOC emissions for each screening period (e.g. month, quarter, year) as follows:

$$E_{VOCP-10} = \sum_{i=1}^{6} CC_i * PF_{iP-10} * t$$

Where:

$E_{VOCP-10}$ = VOC emissions for components pegged over SV 9,999 ppmv (kg/screening period)
i = component type (1=valve, 2=pump seal, 3=others, 4=connector, 5=flange, 6=open-ended line)
CC_i = number of i components pegged over 9,999 ppmv
PF_{iP-10} = VOC emission factor (kg/hr) for component type i pegged over 9,999 ppmv (see Appendix A, Table 14)
t = time component has been leaking (hours) – default value is time since last screening

d. Pegged components over 99,999 ppmv. The operator shall calculate VOC emissions for each screening period (e.g. month, quarter, year) as follows:

$$E_{VOCP-100} = \sum_{i=1}^{6} CC_i * PF_{iP-100} * t$$

Where:

$E_{VOCP-100}$ = VOC emissions for components pegged over 99,999 ppmv (kg/screening period)
i = component type (1=valve, 2=pump seal, 3=others, 4= connector, 5=flange, 6=open-ended line)
CC_i = number of i components pegged over 99,999 ppmv
PF_{iP-100} = VOC emission factor (kg/hr) for component type i pegged over 99,999 ppmv (see Appendix A, Table 14)
t = time component has been leaking (hours)- default value is time since last screening

4. The operator shall calculate and report methane emissions in the following manner:

$$CH_4 = \sum_{1}^{n} (E_{VOC-0} + E_{VOC-LC} + [E_{VOCP-10} \text{ or } E_{VOCP-100}]) * CF_{VOC} * 0.001$$

Where:

CH4 = methane emissions (metric tonnes/year)

n = number of screenings/year

E_{VOC-0} = zero component VOC emissions (kg/screening period)

E_{VOC-LC} = leaking component VOC emissions (kg/screening period)

$E_{VOCP-10}$ = VOC emissions for components pegged over 9,999 ppmv (kg/screening period)

$E_{VOCP-100}$ = VOC emissions for components pegged over 99,999 ppmv (kg/screening period)

CF_{VOC} = VOC to CH4 conversion factor (default CF_{VOC}=0.6)

0.001 = conversion factor – kg to metric tonnes

The operator shall include the term $E_{VOCP-10}$ if the local air district authorizes the use of correlation equations for screening values between background and 9,999 ppmv. Operators shall include the term $E_{VOCP-100}$ if the local air district authorizes the use of correlation equations for screening values between background and 99,999 ppmv.

Where available, operators shall use system specific determinations of gas composition and methane content (refinery fuel gas, natural gas, associated gas, flexigas, low Btu gas) to determine a CF_{VOC} value. When representative data is not available, operators shall use the default value (CF_{VOC} = 0.6) provided by ARB.

(d) *Calculation of Emissions from Flares and Other Control Devices.*

(1) The operator shall calculate and report CO_2, CH_4 and N_2O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in sections 95113(a)(1) and (2).

(2) The operator shall calculate and report CO_2 (and CH_4 where applicable) emissions resulting from the combustion of hydrocarbons routed to flares for destruction using one of the methods specified below:

(A) Operators required to report CH_4 and NMHC emissions to a local Air Quality Management District or Air Pollution Control District shall calculate CO_2 emissions as follows:

$$CO_2 = \sum_{1}^{365} [CF_{NMHC}*NMHC*FE/(100-FE)*3.664+CH_4*FE/(100-FE)*2.743] * 0.001$$

Where:

CO_2 = emissions of CO_2 (metric tonnes/yr)

CF_{NMHC} = carbon fraction in NMHC (CF_{NMHC} = 0.6)

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NMHC = flare non-methane hydrocarbon emissions (kg/day)
CH_4 = flare methane emissions (kg/day)
FE = flare destruction efficiency (%)
3.664 = conversion factor – carbon to carbon dioxide
2.743 = conversion factor – methane to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

When sampling to determine the actual value of CF_{NMHC} is mandated by the AQMD/APCD, the operator shall use the measured value in lieu of 0.6.

The operator shall use flare destruction efficiencies (FE) specified by the local APCD/AQMD.

The operator shall also report the sum of all flare CH_4 emissions reported to the local AQMD/APCD for the report year (metric tonnes/yr).

(B) The operator who is subject to Rule 1118, Control of Emissions from Refinery Flares (South Coast Air Quality Management District), shall calculate ROG as specified in Attachment B of Rule 1118 and report flare CO_2 emissions as follows:

$$CO_2 = \sum_{1}^{365} (CF_{ROG} * [ROG * FE/(100-FE)] * 3.664) * 0.001$$

Where:
CO_2 = emissions of CO_2 (metric tonnes/yr)
CF_{ROG} = carbon fraction in ROG (CF_{ROG} = 0.6)
ROG = reactive organic gas flare emissions (kg/day)
FE = flare destruction efficiency (%)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

The operator shall use flare destruction efficiencies (FE) specified by the local AQMD/APCD.

(C) The operator who is not required to report flare emissions to a local AQMD/APCD shall calculate CO_2 emissions as shown below:

$$CO_2 = RFT * EF_{NMHC} * CF_{NMHC} * 3.664 * 0.001$$

Where:
CO_2 = CO_2 emissions (metric tonnes/year)
RFT = refinery feed through-put (m^3/yr)
EF_{NMHC} = non-methane hydrocarbon emission factor (EF_{NMHC} = 0.002 kg/m^3 through-put)

CF_{NMHC} = conversion factor – NMHC to carbon (CF_{NMHC}= 0.6)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

(3) The operator who utilizes other methods for the destruction of low Btu gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) such as incineration or combustion as a supplemental fuel in heaters, boilers etc., shall calculate and report CO_2 emissions as specified below:

$$CO_2 = GV_A * CC_A * MW_A * 1/MVC * 3.664 * 0.001$$

Where:
CO_2 = CO_2 emissions (metric tonnes/year)
GV_A = volume of gas A destroyed annually (scf/year)
CC_A = carbon content of gas A (kg C/kg fuel)
MW_A = molecular weight of gas A
MVC = molar volume conversion factor (849.5 scf/kg- mole for STP of 20°C and 1 atmosphere or 836 scf/kg-mole, fo r STP of 60°F, and 1 atmosphere)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

The operator shall determine CC_A and MW_A quarterly (four times per year) using methods specified in section 95125(d)(3)(A) and compute an annual average value. GV_A shall be determined to assure accuracy within ± 7.5%.

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

§ 95114. Data Requirements and Calculation Methods for Hydrogen Plants.

(a) *Greenhouse Gas Emissions Data Report.* The operator of a hydrogen production facility specified in section 95101(b), shall include in the emissions data report for each report year the information required by this section, using the calculation methods specified.

   (1) *Fuel and Feedstock Consumption.* Fuel consumption and feedstock consumption in the report year by fuel/feedstock type (including petroleum coke) 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 solid fuels.

   (2) *Production.* The operator shall report the total hydrogen produced at the facility in the report year (scf) and the amount of hydrogen sold for use as transportation fuel (scf).

   (3) *Stationary Combustion – CH_4 and N_2O.* The operator shall calculate and report CH_4 and N_2O emissions from stationary combustion sources using methods specified in section 95125(b), (metric tonnes).

   (4) *Fugitive Emissions.* The operator shall calculate and report fugitive emissions using the methods specified in section 95113(c), (metric tonnes).

   (5) *Flaring Emissions.* The operator shall calculate and report emissions from flares and control devices (if these emissions are not calculated using other methods specified in this regulation) using the methods specified in section 95113(d), (metric tonnes).

   (6) *Transferred CO_2 and CO.* The operator shall calculate and report the amount of CO_2 and CO sold as transferred carbon dioxide and carbon monoxide respectively, (metric tonnes). Transferred carbon dioxide and carbon monoxide shall not be subtracted from total CO_2 emissions reported.

   (7) *Process Vent Emissions.* The operator shall report process vent emissions not reported using other methods specified in this regulation as specified in section 95113(b)(3), (metric tonnes)

   (8) *Sulfur Recovery Process Emissions.* The operator shall report CO_2 process emissions from sulfur recovery units as specified in section 95113(b)(5), (metric tonnes).

   (9) *Electricity Generating Units.* The operators of hydrogen plants with electricity generating units subject to the requirements of this article shall meet the requirements of section 95111.

(10) **Cogeneration Emissions.** The operators of hydrogen plants with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(11) **Indirect Energy Purchases.** The operator shall report all indirect energy purchased and consumed as specified in sections 95125(k)-(l).

(12) **Stationary Combustion and Process CO_2 Emissions.** The operator shall calculate and report stationary combustion and process CO_2 emissions as specified in section 95114(b), (metric tonnes).

(b) **Calculation of CO_2 Stationary Combustion and Process Emissions.** The operator shall calculate and report CO_2 stationary combustion and process emissions using one of the methods specified in this section.

(1) **Continuous Emission Monitoring Systems.** The operator may elect to calculate CO_2 process and stationary combustion using Continuous Emissions Monitoring Systems (CEMS) as specified in section 95125(g)(7).

(2) **Fuel and Feedstock Mass Balance.** The operator may elect to calculate CO_2 process and stationary combustion emissions using the method specified below.

$$CO_2 \text{ (Fuel)} = \sum_1^n \sum_1^x (F_a * CF_a) * 3.664 * 0.001$$

$$CO_2 \text{ (Feedstock)} = \sum_1^n \sum_1^y [(FS_b * CF_b) - S] * 3.664 * 0.001$$

$$CO_2 \text{ (Mass Balance)} = CO_2 \text{ (Fuel)} + CO_2 \text{ (Feedstock)}$$

Where:
   $CO_2(\ )$ = carbon dioxide (fuel) (feedstock) and (mass balance) emissions (metric tonnes/year)
   n = days of operation per reporting period
   F_a = fuel a consumption rate (scf or gallon/day)
   x = total number of fuels
   CF_a = carbon content of fuel a (kg C/scf or gallon fuel)
   FS_b = feedstock b consumption rate (scf/day)
   CF_b = carbon content of feedstock b (kg C/scf feedstock)
   y = total number of feedstocks
   S = carbon accounted for elsewhere (kg C/day)
   3.664 = conversion factor – carbon to carbon dioxide

0.001 = conversion factor – kg to metric tonnes

The operator shall limit the application and use of factor S to situations where CO_2 and/or CH_4 emissions are accounted for using other methods specified in these regulations (for example: uncoverted carbon contained in PSA off-gas or hydrogen plant product that is diverted to fuel gas systems, fed to downstream units and recovered as fuel gas or hydrogen plant feed or diverted to flare where emissions are calculated and reported using applicable methods specified in this regulation). The operator shall determine the carbon content of all feedstock mixtures daily. The operator shall determine the carbon content of natural gas that is not mixed with another fuel or feedstock prior to consumption once per month. The operator shall choose sampling locations in a manner that minimizes bias.

(3)   **Fuel Stationary Combustion and Feedstock Process Emissions.** The operator may elect to calculate CO_2 process and stationary combustion emissions using the methods specified below.

(A)   The operator shall calculate CO_2 stationary combustion emissions using methods specified in section 95113(a)(1)

(B)   The operator shall calculate CO_2 process emissions using the method specified in this section.

$$CO_2 = \sum_{1}^{n} \sum_{1}^{x} [(FSR_i * CF_i) - S] * 3.664 * 0.001$$

Where:
   CO_2 = carbon dioxide emissions (metric tonnes/yr)
   n = number of operational days
   x = number of feedstocks
   FSR_i = feedstock i supply rate (scf/day)
   CF_i = carbon content of feedstock i (kg C/scf feedstock)
   S = carbon accounted for elsewhere (kg C/day)
   3.664 = conversion factor – carbon to carbon dioxide
   0.001 = conversion factor – kg to metric tonnes

The operator shall limit the application and use of factor S to situations where CO_2 and/or CH_4 emissions are accounted for using other methods specified in these regulations (for example: unconverted carbon contained in PSA off-gas or hydrogen plant product that is diverted to fuel gas systems, fed to downstream units and recovered as fuel gas or hydrogen plant feed or diverted to flare where emissions are calculated and reported using applicable methods specified in this regulation). The operator shall determine the carbon content of all feedstock mixtures

daily. The operator shall determine the carbon content of natural gas that is not mixed with another fuel or feedstock prior to consumption once per month. The operator shall choose sampling locations in a manner that minimizes bias.

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

§ 95115. Data Requirements and Calculation Methods for General Stationary Combustion Facilities.

(a) *Emissions data report.* The operator of any facility specified in section 95101(b)(8) that emits greater than or equal to 25,000 metric tonnes per year of CO_2 from stationary combustion sources shall submit an emissions data report for each report year. The operator shall include the following information in the emissions data report:

(1)   Stationary combustion emissions:
    (A)   Total CO_2 emissions (metric tonnes)
        1. CO_2 emissions from biomass-derived fuels (metric tonnes)
    (B)   Total CH_4 emissions (metric tonnes)
    (C)   Total N_2O emissions (metric tonnes)

(2)   Fuels information:
    (A)   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 solid fuels. The operator shall determine and provide consumption of each fuel by direct measurement for the report year. If there are no installed devices for direct measurement of fuel consumption, facilities shall determine consumption on the basis of recorded fuel purchase or sales invoices measuring any stock change (measured in million Btu, gallons, million standard cubic feet, short tons or bone dry short ,tons) using the following equation:

> *Fuel Consumption in the Report Year = Total Fuel Purchases – Total Fuel Sales + Amount Stored at Beginning of Year – Amount Stored at Year End*

For reporting, Btu fuel consumption values shall be converted to million standard cubic feet, gallons, short tons, or bone dry short tons, using heat content values provided by the supplier, measured by the facility, or using values provided in Table 4 of Appendix A.

    (B)   Average annual carbon content as a percent by fuel type, if measured or provided by fuel supplier.
    (C)   Average annual high heat value by fuel type if measured or provided by fuel supplier, reporting in units of MMBtu per fuel unit as specified in section 95115(a)(2)(A).

(3)   Indirect energy usage:
    (A)   Electricity purchases from each electricity provider (kWh)
    (B)   Steam, heat, and cooling purchases from each energy provider (Btu)

(b) **Calculation of CO₂ Emissions.** The operator shall calculate emissions of CO_2 as specified below.

(1) The operator of a crude oil or natural gas production facility identified with the NAICS code 211111 shall report CO_2 emissions from stationary combustion according to the methods specified in sections 95125(c),(d), and(f).

   (A) For natural gas and associated gas, the operator shall use the method specified in section 95125(c) or 95125(d).
   (B) For low Btu gases, the operator shall report emissions resulting from the combustion and/or destruction of low Btu gases as specified in section 95113(d)(3) or section 95125(f), as applicable.
   (C) For fuel mixtures, the operator shall apply the method specified in section 95125(f).

(2) For all other facilities, the operator shall measure and report CO_2 emissions from stationary combustion using one of the following methods:

   (A) Use of a continuous emissions monitoring systems (CEMS) as specified in section 95125(g);
   (B) Use of default emission factors and high heat values as specified in section 95125(a).
   (C) Where a default high heat value is not supplied for a specific fuel type in Appendix A, the operator shall use the method provided in section 95125(c), (d), or (h) to calculate CO_2 emissions.
   (D) Operators not using CEMS who co-fire two or more types of fuels shall select methods specified in sections 95115(b)(1)-(2) that enable the operator to separately report CO_2 emissions for each fuel type. Operators who co-fire with waste-derived fuels that are partly but not pure biomass may elect to determine the biomass portion of total CO_2 emissions resulting from the combustion of the co-fired fuels using the method specified in section 95125(h)(2).

(c) **Calculation of N₂O and CH₄ Emissions.** The operator shall calculate emissions of N_2O and CH_4 emissions from stationary combustion using the methodologies provided in section 95125(b).

(d) **Electricity Generating Units.** Operators of general stationary combustion facilities with electricity generating units subject to the requirements of this article shall meet the requirements of section 95111.

(e) **Cogeneration.** Operators of general stationary combustion facilities with cogeneration systems subject to the requirements of this article shall meet the requirements of section 95112.

(f) **_Indirect Energy Usage._** Operators of general stationary combustion facilities shall calculate indirect electricity and thermal energy purchased or acquired and consumed as specified in sections 95125(k)-(l).

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

Subarticle 3. Calculation Methods Applicable to Multiple Types of Facilities

§ 95125. *Additional Calculation Methods.* Operators shall use one or more of the following methods to calculate emissions as required in sections 95110 through 95115.

(a) **Method for Calculating CO_2 Emissions from Fuel Combustion Using Default Emission Factors and Default Heat Content.**

(1)   The operator shall use the method in section 95125(a)(2) to calculate CO_2 emissions, applying the default emission factors and default heat content values provided in the Appendix A, for each type of fuel combusted at the facility.

(2)   The operator shall calculate each fuel's CO_2 emissions and report them in metric tonnes using the following equation:

$$CO_2 = \text{Fuel} * HHV_D * EF_{CO2} * 0.001$$

Where:
CO_2 = CO_2 emissions from a specific fuel type, metric tonnes CO_2 per year
Fuel = Mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year
HHV_D = Default high heat value specified by fuel type supplied by ARB, MMBtu per unit of mass or volume
EF_{CO2} = Default carbon dioxide emission factor provided in Appendix A, kg CO_2 per MMBtu
0.001 = Factor to convert kg to metric tonnes

(b) **Method for Calculating CH_4 and N_2O Emissions from Fuel Combustion Using Default Emission Factors.**

(1)   The operator shall use the methods in this section to calculate CH_4 and N_2O emissions, applying the default emission factors provided in the Appendix A for each type of fuel, except as provided in section 95125(b)(4). If the operator measures heat content as specified in section 95125(c), the measured heat content shall be used in the equation in section 95125(b)(2). If the heat content is not measured, the operator shall employ the default heat content values specified in Appendix A by fuel type and the equation specified in section 95125(b)(3). If an operator combusts a fuel whose heat content is not provided in Appendix A, the operator shall measure heat content as specified by fuel type in section 95125(c) and utilize the N_2O and CH_4 emissions methodology specified in section 95125(b)(2). Operators may elect to determine N_2O and CH_4 emissions using the method specified

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in section 95125(b)(4) in lieu of the methods provided in sections 95125(b)(2)-(3).

(2) If the heat content of the fuel is measured, the operator shall calculate each fuel's CH_4 and N_2O emissions and report them in metric tonnes using the following equation:

$$CH_4 \text{ or } N_2O = \sum_{1}^{n} Fuel_P * HHV_P * EF * 0.001$$

Where:

CH_4 or N_2O = combustion emissions from specific fuel type, metric tonnes CH_4 or N_2O per year

n = Period/frequency of heat content measurements over the year (e.g. monthly n = 12)

$Fuel_P$ = Mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time

HHV_P = High heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume

EF = Default CH_4 or N_2O emission factor provided in Appendix A, kg CH_4 or N_2O per MMBtu

0.001 = Factor to convert kg to metric tonnes

(3) If the heat content of the fuel is not measured, the operator shall calculate each fuel's CH_4 and N_2O emissions and report them in metric tonnes using the following equation:

$$CH_4 \text{ or } N_2O = Fuel * HHV_D * EF * 0.001$$

Where:

CH_4 or N_2O = CH_4 or N_2O emissions from a specific fuel type, metric tonnes CH_4 or N_2O per year

Fuel = Mass or volume of fuel combusted specified by fuel type, unit of mass or volume per year

HHV_D = Default high heat value specified by fuel type provided in Appendix A, MMBtu per unit of mass or volume

EF = Default emission factor provided in Appendix A, kg CH_4 or N_2O per MMBtu

0.001 = Factor to convert kg to metric tonnes

(4) The operator may elect to calculate CH_4 and N_2O emissions using ARB approved source specific emission factors derived from source tests conducted at least annually under the supervision of ARB or the local air pollution control district or air quality management district. Upon approval of a source test plan by ARB, the source test procedures in that plan shall be repeated in future years to update the source specific emission factors

annually. In the absence of source specific emission factors approved by ARB, the operator shall use the default emission factors provided in Appendix A.

(c) **Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Heat Content.**

(1) The operator shall use the following equation to calculate fuel combustion CO_2 emissions by fuel type using the measured heat content of the fuel combusted:

$$CO_2 = \sum_{1}^{n} Fuel_P * HHV_P * EF * 0.001$$

Where:

CO_2 = combustion emissions from specific fuel type, metric tonnes CO_2 per year

n = Period/frequency of heat content measurements over the year (e.g. monthly n = 12)

$Fuel_P$ = Mass or volume of fuel combusted for the measurement period specified by fuel type, units of mass or volume per unit time

HHV_P = High heat value measured for the measurement period specified by fuel type, MMBtu per unit mass or volume

EF = Default carbon dioxide emission factor provided in the Appendix A, kg CO_2 per MMBtu

0.001 = Factor to convert kg to metric tonnes

(A) The operator shall measure and record fuel consumption and the fuel's high heat value at frequencies specified by fuel type below. The operator may elect to utilize and record high heat values provided by the fuel supplier. The frequencies for measurements and recordings are as follows:

1. At receipt of each new fuel shipment or delivery or on a monthly basis for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-Butane, unspecified LPG);

2. Monthly for natural gas, associated gas, and mixtures of low Btu gas excluding refinery fuel gas. Operators combusting gases with high heat value <975 or >1100 Btu per scf including natural gas, associated gas, and mixtures of low Btu gas and natural gas, shall use the methodology provided in section 95125(d) to calculate CO_2 emissions;

3. Monthly for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.

4. The heat content of all solid fuels shall be measured and recorded monthly. The monthly solid fuel sample shall be a composite sample of weekly samples. The solid fuel shall be sampled at a location after all fuel treatment operations and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion. Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased. Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample. The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis. One in twelve composite samples shall be randomly selected for additional analysis of its discreet constituent samples. This information will be used to monitor the homogeneity of the composite.

(B) When measured by the operator or fuel supplier, high heat values shall be determined using one of the following methods:

1. For gases, use ASTM D1826-94 (Reapproved 2003), ASTM D3588-98 (Reapproved 2003), ASTM D4891-89 (Reapproved 2006), GPA Standard 2261-00 "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography." The operator may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heating value, the operator shall convert the value to high heating value as specified in section 95125(c)(1)(C).

2. For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02 (Reapproved 2007), ASTM D240-87 (Reapproved 1991), ASTM D4809-00 (Reapproved 2005).

3. For solid biomass-derived fuels use ASTM D5865-07a.

4. For waste-derived fuels use ASTM D5865-07a or ASTM D5468-02 (Reapproved 2007). Operators who combust waste-derived fuels that are partly but not pure biomass shall determine the biomass-derived portion of CO_2 emissions using the method specified in section 95125(h)(2), if applicable

(C) Operators of facilities where currently installed on-line instrumentation provides a measure of lower heating value (LHV) but not higher heating value (HHV), shall convert LHVs (Btu/scf) to HHVs (Btu/scf) in the following manner.

$$HHV = LHV * CF$$

Where:

HHV = fuel or fuel mixture higher heating value (Btu/scf)
LHV = fuel or fuel mixture lower heating value (Btu/scf)
CF = conversion factor

For natural gas, operators shall use a CF of 1.11.
For refinery fuel gas and mixtures of refinery fuel gas, operators shall derive a fuel system specific CF. A weekly average CF shall be determined from either concurrent LHV instrumentation measurements and HHV determined as part of the daily carbon content determination, either by on-line instrumentation or laboratory analysis, or by the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

(d) **Method for Calculating CO_2 emissions from Fuel Combustion Using Measured Carbon Content -** For each type of fuel combusted at the facility, the operator shall calculate CO_2 emissions using the appropriate method below:

(1) **Solid Fuels.**

(A) Operators combusting solid fuels shall use the following equation to calculate CO_2 emissions:

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 3.664$$

Where:

CO_2 = carbon dioxide emissions, metric tonnes per year
$Fuel_n$ = mass of fuel combusted in month "n," metric tonnes
CC_n = carbon content from fuel analysis for month "n," percent (e.g. 95% expressed as 0.95)
3.664 = conversion factor for carbon to carbon dioxide

(B) The carbon content of all solid fuels shall be measured and recorded monthly. The monthly solid fuel sample shall be a composite sample of weekly samples. The solid fuel shall be sampled at a location after all fuel treatment operations and the samples shall be representative of the fuel chemical characteristics combusted during the sample week. Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and

unbiased. Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample. The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis. One in twelve composite samples shall be randomly selected for additional analysis of its discreet constituent samples. This information will be used to monitor the homogeneity of the composite.

(C) When measured by the operator or fuel supplier, carbon content shall be determined using the following ASTM method:

1. For coal and coke, solid biomass-derived fuels, and waste-derived fuels use ASTM 5373-02 (Reapproved 2007).

(2) ***Liquid Fuels.***

(A) Operators combusting liquid fuels shall use the following equation to calculate CO_2 emissions:

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 3.664 * 0.001$$

Where:

CO_2 = carbon dioxide emissions, metric tonnes per year
$Fuel_n$ = volume of fuel combusted in month "n," gallons
CC_n = carbon content from fuel analysis for month "n," kg C per gallon fuel
3.664 = conversion factor for carbon to carbon dioxide
0.001 = factor to convert kg to metric tonnes

(B) The carbon content shall be measured and recorded monthly. When measured by the operator or fuel supplier, carbon content shall be determined using the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 (Reapproved 2007) "Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants," ultimate analysis of oil or computations based on ASTM D3238-95 (Reapproved 2005) and either ASTM D2502-04 or ASTM D2503-92 (Reapproved 2002).

(3) **Gaseous Fuels.** Operators combusting gaseous fuels shall use the following equation to calculate CO_2 emissions:

$$CO_2 = \sum_{1}^{12} Fuel_n * CC_n * 1/MVC * 3.664 * 0.001$$

   Where:
   > CO_2 = carbon dioxide emissions, metric tonnes per year
   > $Fuel_n$ = volume of gaseous fuel combusted in month "n," scf
   > CC_n = carbon content from fuel analysis for month "n," kg C per kg-mole fuel
   > MVC = molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole fo r STP of 60°F and 1 atmosphere)
   > 3.664 = conversion factor for carbon to carbon dioxide
   > 0.001 = Factor to convert kg to metric tonnes

(A) When measured by the operator or fuel supplier, carbon content shall be determined using the following ASTM methods: ASTM D1945-03 or ASTM D1946-90 (Reapproved 2006). Except for refinery fuel gas and flexicoker derived fuel gas, the carbon content shall be measured and recorded monthly. Petroleum refiners electing to use this method to calculate CO_2 emissions resulting from the combustion of refinery fuel gas shall determine refinery fuel gas carbon content (CC) a minimum of 3 times per day (every eight hours) using on-line instrumentation or discrete sample laboratory analysis. The carbon content of flexigas shall be determined once per day with either on-line instrumentation or discrete sampling and lab based analysis using one of the ASTM methods listed above. Operators shall calculate CO_2 emissions for a refinery fuel gas system and flexigas combustion in the following manner:

$$CO_2 = \sum_{1}^{365} Fuel_n * CC_{An\text{-}ave} * MW_{RFG\text{-}A}/MVC * 3.664 * 0.001$$

   Where:
   > CO_2 = carbon dioxide emissions, metric tonnes/year
   > $Fuel_A$ = refinery fuel or flexigas from system A combusted on day n (scf)
   > $CC_{An\text{-}ave}$ = system A refinery fuel gas average daily carbon content or flexigas carbon content for day n (kg C/kg fuel)
   > $MW_{RFG\text{-}A}$ = average daily molecular weight of refinery fuel gas system A or flexigas molecular weight for day n

MVC = molar volume conversion factor (849.5 scf/kg-mole for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole fo r STP of 60°F and 1 atmosphere)
3.664 = conversion factor – carbon to carbon dioxide
0.001 = conversion factor – kg to metric tonnes

(4) Operators who combust waste-derived fuels that are partly but not pure biomass and who determine CO_2 emissions using methods provided in sections 95125(d)(1)-(3) shall determine the biomass-derived portion of CO_2 emissions using the method specified in section 95125(h)(2), if applicable.

(e) **Method for Calculating CO_2 Emissions from Fuel Combustion Using Measured Heat and Measured Carbon Content.**

(1) The operator shall use the following method to calculate CO_2 emissions from combustion of refinery fuel gas using both high heat value (HHV) and fuel carbon content.

(2) Each fuel gas system that provides fuel to one or more combustion devices shall be subject to the measurement and reporting methods described herein. The operator shall obtain fuel samples and choose measurement locations in a manner that minimizes bias and is representative of each fuel gas system.

(3) For each separate fuel gas system, the operator shall calculate a daily fuel specific emission factor using the equation shown below. Operators meeting the definition of "small refiner" shall calculate a weekly emission factor for each refinery fuel gas system.

$$EF_{CO2-A} = CC_A/HHV_A * MW_A/MVC * 3.664 * 1000$$

Where:
EF_{CO2-A} = daily CO_2 emission factor for fuel gas system A (metric tonnes CO_2/MMBtu)
CC_A = fuel gas carbon content for fuel gas system A (kg carbon/kg fuel)
HHV_A = high heating value for fuel gas system A (Btu/scf)
MW_A = refinery fuel A molecular weight (kg/kg-mole)
MVC = molar volume conversion (849.5 scf/ kg-mole, for STP of 20°C and 1 atmosphere, or 836 scf/kg-mole for STP of 60°F and 1 atmosphere)
3.664 = conversion factor – carbon to carbon dioxide
1000 = conversion factor – kg/Btu to metric tonnes/MMBtu

(A) The operator shall determine carbon content once per day for each fuel gas system, by on-line instrumentation or by laboratory analysis of

a representative gas sample drawn from the system, using the method specified in section 95125(d)(3). Small refiners shall determine carbon content weekly.

(B)   The operator shall determine high heating value from the fuel sample obtained to conduct carbon analysis, or from continuous on-line instrumentation. When HHV_A is derived from on-line instrumentation, operators shall use either an hourly average HHV value coinciding with the hour in which the carbon content determination was made, or the hour in which the sample was collected for analysis. The operator shall use the method specified in section 95125(c)(1)(B). Operators of facilities with installed instrumentation which provides fuel or fuel mixture LHV (Btu/scf) shall use methods specified in section 95125(c)(1)(C) for the conversion of LHV to HHV.

(4)   For each refinery fuel gas system the operator shall use the system specific daily (weekly for small refiners) fuel emission factor calculated using the equation in section 95125(e)(3) to calculate daily (weekly for small refiners) CO_2 emissions from all combustion devices where the fuel gas from that system was combusted, using the following equation.

$$CO_{2-A} = \sum_{1}^{365} HHV_{DA} * FR_A * EF_{CO2-A} * 0.000001$$

Where:
  CO_{2-A} = CO_2 emissions resulting from the combustion of fuel gas from system A (metric tonnes/yr)
  HHV_{DA} = daily average high heating value for system A (Btu/scf)
  FR_A = daily fuel consumption for fuel gas system A (scf/d)
  EF_{CO2-A} = daily CO_2 emission factor for fuel gas system A (tonnes CO_2/MM Btu)
  0.000001 = conversion factor – Btu to MMBtu

  The operator shall determine the daily average high heating value (HHV_{DA}) from continuous on-line instrumentation (except for small refiners). Small refiners may use the HHV value determined as part of the weekly fuel carbon content analysis to calculate weekly CO_2 emissions.

(5)   The operator shall calculate and report total CO_2 emissions resulting from the combustion of fuel gas as the sum of CO_2 combustion emissions from each fuel gas system in the following manner:

$$CO_2 = CO_{2\text{-}A} + CO_{2\text{-}B} + CO_{2\text{-}C} + \ldots\ldots CO_{2\text{-}X}$$

Where:

CO_2 = total CO_2 emissions from the combustion of fuel gas (metric tonnes/yr)

$CO_{2A,B,C}$ = CO_2 emissions from the combustion sources in fuel gas system A,B,C, etc. (metric tonnes/yr)

$CO_{2\text{-}X}$ = CO_2 emissions from the combustion of fuel gas system X, where X is the total number of fuel gas systems (metric tonnes/yr)

(f) **Method for Calculating CO_2 Emissions from Fuel Combustion for Fuel Mixtures. (Petroleum Refineries and Crude Oil and Natural Gas Processing Facilities)**

(1) Where individual fuels are mixed prior to combustion, the operator shall choose one of the methods below to calculate and report CO_2 emissions.

(A) Determine fuel flow rate and appropriate fuel specific parameters (carbon content, HHV) of each fuel stream prior to mixing, calculate CO_2 emissions for each fuel in the mixture using the appropriate methodology (specified in section 95125(c) for natural gas and associated gas, 95125(f)(1)(B)-(D) for refinery fuel gas and flexigas, and 95113(d)(3) for low Btu gas) and sum individual fuel emissions to calculate emissions resulting from combustion of the mixture.

(B) Determine CO_2 emissions using a Continuous Emissions Monitor System (CEMS) as specified in section 95125(g).

(C) Operators of petroleum refineries where refinery fuel gas is mixed with natural gas and/or low Btu gas shall use the methods specified in sections 95125(d)(3)(A) or 95125(e),

(D) Operators of oil and gas production facilities and natural gas production and processing facilities where associated gas or low Btu gas is mixed with natural gas prior to combustion shall use methods specified in section 95125(c).

(g) **Method for Calculating CO_2 Emissions Using Continuous Emissions Monitoring Systems.**

(1) The operator of a facility that combusts fossil fuels or biomass and operates continuous emissions monitoring systems (CEMS) in response to federal, state, or air pollution control district/air quality management district (AQMD/APCD) regulations, including 40 CFR Part 60 or 40 CFR Part 75, may use CO_2 or O_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. The operator shall report CO_2 emissions for the report year in metric tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to metric tonnes.

(A)   If the operator of a facility that combusts biomass uses O_2 concentrations to calculate CO_2 concentrations, annual source testing must demonstrate that calculated CO_2 concentrations when compared to measured CO_2 concentrations meet the Relative Accuracy Test Audit (RATA) requirements in 40 CFR Part 60, Appendix B, Performance Specification 3.

(2)   The operators of a facility that combusts municipal solid waste or other waste-derived fuels and operates a CEMS in response to federal, state, or AQMD/APCD regulations, including 40 CFR Part 60 or 40 CFR Part 75, may use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. The operator shall report CO_2 emissions for the report year in metric tonnes based on the sum of hourly CO_2 mass emissions over the year and converted to metric tonnes. Emissions calculations shall not be based on O_2 concentrations.

(3)   The operator of a facility that combusts municipal solid waste or other waste-derived fuels who chooses to calculate CO_2 emissions using the methodology provided in section 95125(g)(2) shall determine the portion of emissions associated with the combustion of biomass-derived fuels using the method provided in section 95125(h)(2), if applicable.

(4)   The operator who chooses to use CEMS data to report CO_2 emissions from a facility that co-fires fossil fuels with biomass or waste-derived fuels that are partly biomass shall determine the portion of total CO_2 emissions separately assigned to the fossil fuel and the biomass-derived fuel using the method provided in section 95125(h)(2), if applicable. The operator who co-fires pure biomass with fossil fuels may elect to calculate CO_2 emissions for the fossil fuels using methods designated in section 95111(c) by fuel type and then subtract the fossil fuel related emissions from the total CO_2 emissions determined using the CEMS based methodology.

(5)   The operator who chooses to report CO_2 emissions using CEMS data is relieved of requirements to separately report process emissions from combustion emissions or to report emissions separately for different fossil fuels when only fossil fuels are co-fired. In this circumstance operators shall still report fuel use by fuel type as otherwise required in this article.

(6)   If a facility is subject to requirements in 40 CFR Part 60 or 40 CFR Part 75 and the operator chooses to add devices to an existing continuous monitoring system for the purpose of measuring CO_2 concentrations or flue gas flow, the operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 60 or Part 75 that apply to the facility. If the facility is subject to both 40 CFR Part 60 and 40 CFR Part 75, the

operator shall select and operate the added devices pursuant to the requirements in 40 CFR Part 75.

(7)   If a facility does not have a continuous emissions monitoring system and the operator chooses to add one in order to measure CO_2 concentrations, the operator shall select and operate the CEMS pursuant to the requirements in 40 CFR Part 75. The operator shall use CO_2 concentrations and flue gas flow measurements to determine hourly CO_2 mass emissions using methodologies provided in 40 CFR Part 75, Appendix F. The operator shall report CO_2 emissions for the report year in metric tonnes based on the sum of hourly CO_2 mass emissions over the year, converted to metric tonnes. Operators who add CEMS under this article are subject to specifications in section 95125(g)(3)-(6), if applicable.

(h) **Method for Calculating CO_2 Emissions from Combustion of Biomass, Municipal Solid Waste, or Waste Derived Fuels with Biomass.**

(1)   The operator shall use the following method to calculate CO_2 emissions in the report year from combustion of biomass solid fuels or municipal solid waste.

(A) CO_2 emissions from combusting biomass or municipal solid waste shall be calculated using the following equation:

$$CO_2 = Heat * CC_{EF} * 3.664 * 0.001$$

Where:
CO_2 = CO_2 emissions from fuel combustion, metric tonnes per year
Heat = Heat calculated in section 95125(h)(1)(B), MMBtu per year
CC_{EF} = Default carbon content emission factor provided in
          Appendix A,
          kg carbon per MMBtu
3.664 = CO_2 to carbon molar ratio
0.001 = Conversion factor to convert kilograms to metric tonnes

(B)   Heat content shall be calculated using the following equation:

$$Heat = Steam * B$$

Where
Heat   = Heat, MMBtu per year
Steam = Actual Steam generated, pounds per year
B   = Boiler Design Heat Input/Boiler Design Steam Output,
          as Design MMBtu per pound Steam

(2)   The operator that combusts fuels or fuel mixtures that are at least 5 percent biomass by weight and not pure biomass, except waste-derived fuels that are less than 30 percent by weight of total fuels combusted for the report year, shall determine the biomass-derived portion of CO_2 emissions using ASTM D6866-06a as specified in this article. The operator shall conduct ASTM D6866-06a analysis at least every three months, and shall collect each gas sample for analysis during normal operating conditions over at least 24 consecutive hours. The operator shall divide total CO_2 emissions between biomass-derived emissions and non-biomass-derived emissions using the average proportionalities of the samples analyzed. If there is a common fuel source to multiple units at the facility, the operator may elect to conduct ASTM D6866-06a testing for one of the units.

(3)   In lieu of the method provided in section 95125(h)(1), operators of facilities that combust biomass solid fuels, waste-derived fuels, or municipal solid waste may elect to calculate CO_2 emissions using ARB approved source specific emission factors derived from source tests conducted at least annually under the supervision of ARB or the local air pollution control district or air quality management district. For fuels or fuel mixtures that contain at least 5 percent biomass by weight but are not pure biomass, the source test protocol shall include determination of the biomass-derived portion of CO_2 emissions as specified in section 95125(h)(2) if applicable. Upon approval of a source test plan by ARB, the source test procedures in that plan shall be repeated in subsequent years to update the source specific emission factors annually. In the absence of source specific emission factors approved by ARB, the operator shall determine CO_2 emissions using a method otherwise specified for the source in this article.

(i) *Method for Calculating Mobile Combustion Emissions.*

(1)   For operators choosing to report mobile source combustion emissions, the operator shall use the following equation to compute mobile combustion CO_2 emissions for the report year by fuel type:

$$CO_2 = Fuel * EF_{CO2} * 0.001$$

Where:
   CO_2 = emissions from mobile combustion by fuel type, metric tonnes per year
   Fuel   = volume of fuel consumed, gallons per year
   EF_{CO2} = default emission factor by fuel type provided in Appendix A, kg CO_2/gallon
   0.001 = conversion factor to convert kg to metric tonnes

(2)   The operator shall obtain data on the volume of fuel consumed during the report year from fuel records data (including bulk fuel purchase records,

collected fuel receipts, official logs of vehicle fuel gauges or storage tanks) as shown in section 95125(i)(2)(A), unless the operator elects to calculate fuel use from miles traveled per vehicle using the fuel economy method shown in section 95125(i)(2)(B).

(A) The operator shall use the following equation to calculate mobile source fuel consumption from fuel records data:

$$Fuel = FP + FS_{beg} - FS_{end}$$

Where:
Fuel = volume of fuel consumed, gallons per year
FP   = total fuel purchases, gallons per year
FS_{beg} = amount of fuel stored at the beginning of the year, gallons
FS_{end} = amount of fuel stored at the end of the year, gallons

(B) The operator shall use the following equation to calculate mobile source fuel consumption using U.S. EPA fuel economy values for specific vehicle models and miles traveled per vehicle:

$$Fuel = \sum_{i}^{n} Mileage_i / (FE_{city,i} * DP_{city,i} + FE_{highway,i} * DP_{highway,i})$$

Where:
Fuel   = volume of fuel consumed, gallons per year
$Mileage_i$ = total miles traveled by vehicle i, miles per year
$FE_{city,i}$ = U.S. EPA specified vehicle i fuel economy for city driving, miles per gallon
$DP_{city,i}$ = proportion of miles traveled spent in city driving conditions for vehicle i, percent/100 (0.55 may be used as a default value or a fleet specific number may be substituted if known)
$FE_{highway,i}$ = U.S. EPA specified vehicle i fuel economy for highway driving, miles per gallon
$DP_{highway,i}$ = proportion of miles traveled spent in highway driving conditions for vehicle i, percent/100 (0.45 may be used as a default value or a fleet specific number may be substituted if known)
n   = total number of vehicles

(3) The operator shall use the following equation to compute mobile combustion CH_4 and N_2O emissions by vehicle type:

$$TE = EF * Mileage * 0.000001$$

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Where:
    TE   = total emissions of CH_4 or N_2O from mobile combustion
            by vehicle type, metric tonnes per year
    EF   = emission factor by vehicle type and fuel type provided
            in Appendix A, g of CH_4 or N_2O/mile
    Mileage = total miles traveled by vehicle type, miles per year
    0.000001 = conversion factor to convert grams to metric
            tonnes

(A) If mile traveled data are not available, the operator may elect to back
     calculate total miles traveled by vehicle type from fuel usage data
     using U.S. EPA fuel economy values for specific vehicle models and
     the following equation:

$$\text{Mileage} = \sum_{i}^{n} \text{Fuel}_i * (FE_{city,i} * DP_{city,i} + FE_{highway,i} * DP_{highway,i})$$

Where:
    Mileage = total miles traveled by vehicle type, miles per year
    Fuel_i = volume of fuel consumed by vehicle model i,
                gallons per year
    $FE_{city,i}$ = U.S. EPA specified vehicle i fuel economy for city
                driving, miles per gallon
    $DP_{city,i}$ = proportion of miles traveled spent in city driving
                for vehicle i, percent/100 (0.55 may be used as a
                default value or a fleet specific number may
                substituted if known)
    $FE_{highway,i}$ = U.S. EPA specified vehicle i fuel economy for
                highway driving, miles per gallon
    $DP_{highway,i}$ = proportion of miles traveled spent in highway
                driving conditions for vehicle i, percent/100
                (0.45 may be used as a default value or a fleet-
                specific number may be substituted if known)
    n   = number of vehicles

(j) ***Method for Calculating Fugitive CH_4 Emissions from Coal Storage.***

The operator shall calculate fugitive CH_4 emissions from coal storage using the
following equation:

$$CH_4 = PC * EF * CF_1 / CF_2$$

Where
    CH_4 = CH_4 emissions in the report year, metric tonnes per year
    PC =   Purchased coal in the report year, tons per year
    EF =   Default emission factor for CH_4 based on coal origin and mine type
            provided in Appendix A, scf CH_4/ton

$CF_1 =$ Conversion factor equals 0.04228, lbs CH_4/scf
$CF_2 =$ Conversion factor equals 2,204.6, lbs/metric ton

(k) **Method for Calculating Indirect Electricity Usage.**

The operator of a facility that consumes electricity that is purchased or acquired from a retail provider or a facility they do not own or operate shall report electricity use and identify the provider(s) for all electricity consumed at the facility.

(1) For each electricity provider, the operator shall sum electricity use (kWh) from billing records for the report year. If the records do not begin on January 1 and end on December 31 of the report year, but span two calendar years, the facility shall pro-rate its power usage according to the fraction of days billed for each month in each year using the equation shown.

   Calculating electricity use for partial months:

   Partial Month Electricity use (kWh) =
   *(electricity use (kWh) in period billed / total number days in period billed) * (number of report year days in the period billed)*

(2) The operator shall report by electricity provider the electricity consumed at the facility in kilowatt-hours (kWh).

(l) **Method for Calculating Indirect Thermal Energy Usage.**

The operator of a facility that consumes steam, heat, and/or cooling that is purchased or acquired from a facility that they do not own or operate shall report thermal energy use and identify the provider(s) for all thermal energy consumed at the facility.

(1) For each thermal energy provider, the operator shall obtain data from the facility's thermal use records, and sum this usage for the report year. If the records do not begin on January 1 and end on December 31 of the report year, but span two calendar years, the facility shall pro-rate its indirect thermal energy usage according to the fraction of days billed for each month in each year using the equation shown.

   Calculating thermal use for partial months:

   Partial Month Thermal use (Btu) =
   *(thermal use (Btu) in period billed / total number days in period billed) * (number of report year days in the period billed)*

(2)   The operator shall report by thermal energy provider the thermal energy consumed at the facility in British thermal units (Btu).

NOTE: Authority cited: Sections 39600, 39601, 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

§ 95130. Requirements for Verification of Emissions Data Reports. Operators shall obtain the services of an accredited verification body for purposes of verifying emissions data reports submitted under this article, as specified in section 95103(c).

(a) *Annual Verification.*

    (1)   Operators required to obtain annual verification as specified in section 95103(c) shall be subject to full verification requirements in the first year that verification is required. Upon completion of a positive verification opinion under full verification requirements, the operator may choose to obtain two years of less intensive verification services. This cycle may be repeated in subsequent three-year cycles, but full verification requirements shall apply at least once every three years.

    (2)   Operators subject to annual verification shall not use the same verification body for a period of more than six consecutive years. If an operator is required or elects to contract with another verification body, the operator may contract verification services from the previous verification body only after not using the previous verification body for at least three years.

(b) *Triennial Verification.*

    (1)   Operators required to obtain triennial verification under section 95103(c) shall be subject to full verification requirements every year that verification is required. However, such operators may choose to obtain less intensive verification services for the two years following completion of full verification services and prior to the next three-year cycle.

    (2)   Operators subject to triennial verification requirements shall not use the same verification body for more than two consecutive verification cycles. If an operator is required or elects to contract with another verification body, the operator may contract verification services from the previous verification body only after not using the previous verification body for at least three years.

(c) Operators who are members of the California Climate Action Registry may use the same verification body for ARB and CCAR emissions data reports, provided that body has met both ARB and CCAR accreditation requirements. When an operator is required to rotate verification bodies by the California Climate Action Registry, the operator shall also rotate the verification body used to meet the verification requirements of this article if the operator chooses to use the same verification body.

NOTE: Authority cited: Sections 39600, 39601, 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 operator ten working days after the notice is received by the Executive Officer, or earlier if approved by the Executive Officer in writing. 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;

(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 a retail provider or marketer, at least one verification team member must be accredited by ARB as an electricity transactions specialist;
(B)   For providing verification services to the operator of a petroleum refinery or hydrogen plant, at least one verification team member must be accredited by ARB as a refinery specialist;
(C)   For providing verification services to the operator of a cement plant, at least one verification team member must be accredited by ARB as a cement plant specialist.

(3)   General information on the lead verifier and the operator, including:

(A)   The name, office address, telephone number, and e-mail address of the lead verifier;
(B)   The name of the operator and the facilities and other locations that will be subject to verification services, operator contact, address, telephone number, and e-mail address;
(C)   The industry sector, and the Standard Industrial Classification and North American Industry Classification System (NAICS) codes of the reporting facility;

(D) The expected date(s) of on-site visits, with facility address and contact information;

(E) A brief description of expected verification services to be performed, including expected completion date.

(b) Verification services shall include, but are not limited to, the following:

(1) **Verification Plan.** The verification team shall obtain information from the operator 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 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 transactions, and other required data as applicable;

(D) Information about the data management system used to track greenhouse gas emissions, electricity transactions, and other required data as applicable.

(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 operator 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 member of the verification team shall at a minimum make one site visit, in the first year of each three-year reporting cycle, 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 operator is a retail provider or marketer. 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 95115 as applicable to the operator are identified appropriately.

(B)   The verification team member(s) shall review and understand the data management systems used by the operator to track, quantify, and report greenhouse gas emissions and, when applicable, electricity transactions. The verification team member(s) shall evaluate the uncertainty and effectiveness of these systems.

(C)   The verification team shall collect and review other information that, in the professional judgment of the team, is needed in the verification process.

(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 assure that all sources listed in sections 95110 to 95115 of this article are properly included in the inventory.

(6)   Operators shall make available to the verification team all information and documentation used to calculate and report emissions, electricity transactions, and other information required under this article, as applicable.

(7)   As applicable for retail providers and marketers, 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 or electricity 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 an operator. The analysis shall review the inputs for the development of the submitted emissions data report, the rigor and appropriateness of the greenhouse gas or electricity transaction data management system, and the coordination within a facility or retail provider's or marketer'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 operator, and a ranking of emissions sources with

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the largest calculation uncertainty. As applicable and deemed appropriate by the verification team, electricity transactions shall also be ranked or evaluated relative to the amount of power exchanged and uncertainties that may apply to data provided by the retail provider or marketer.

(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 95115:

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)   The verification team may change the sampling plan as relevant information becomes available and potential issues emerge of material misstatement or nonconformance with the requirements of this article.

(E)   The verification body shall retain the sampling plan in paper, electronic, or other format for a period of not less than five years following the submission of each verification opinion. The sampling plan shall be made available to ARB upon request.

(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 first on the largest and most uncertain estimates of emissions 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 electricity transactions covered under sections 95110 to 95115;

(B)   The verification team shall choose emissions sources, and electricity transactions data as applicable, for data checks based on their relative sizes and risks of material misstatement 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 reported emissions and transactions are free of material misstatement and the emissions data report otherwise conforms to the requirements of this article.

(10) **Emissions Data Report Modifications.** If as a result of review by the verification team and prior to completion of a verification opinion the operator chooses to make improvements or corrections to the submitted emissions data report, a revised emissions data report may be submitted to ARB as specified by section 95104(d). The operator 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 operator for five 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 reported facility emissions are within 95 percent of actual total emissions for the facility, on a CO_2 equivalent basis. 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 requirement of this article. The verification team shall keep a log of any issues identified in the course of verification activities that may affect determinations of material misstatement and nonconformance, and how those issues were resolved.

(c) Completion of verification services shall include:

(1) **Verification Opinion.** Upon completion of the verification services specified in section 95131(b), the verification body shall complete a verification opinion, and provide that opinion to the operator and the ARB according to the schedule specified in section 95103(c)(3). Before that opinion is completed, the verification body shall have the verification services and findings of the verification team independently reviewed within the verification body by a lead verifier not involved in services for that operator during that year.

(2) When the verification team completes its findings:

(A) The verification body shall provide to the operator a detailed verification report. The verification report shall at minimum include the verification plan, the detailed comparison of the data checks with the submitted emissions data report, 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 be made available to ARB upon request.

(B) The verification body shall provide the verification opinion to the operator and the ARB, attesting that the verification body has found the submitted emissions data report free of material misstatement and in conformance with the requirements of this article or, alternatively, that

the emissions data report contains material misstatement or otherwise does not conform with the requirements of this article.

    (C)   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 specified in section 95131(c)(1) shall attest to his or her independent review on behalf of the verification body and his or her concurrence with the verification findings.

(3)   Prior to the verification body providing an adverse verification opinion to the ARB, the operator 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 opinion must be submitted to ARB before the applicable verification deadline, unless the operator makes a request to the Executive Officer as provided below in section 95131(c)(3)(A).

    (A)   If the operator and the verification body cannot reach agreement on modifications to the emissions data report that result in a positive verification opinion, the operator 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 operator 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)-(2).

(d) Upon provision of the verification opinion to ARB, the emissions data report shall be considered final and no changes shall be made except as provided in section 95104(d)(3). All verification requirements of this article shall be considered complete.

(e) If the Executive Officer finds a high level of conflict of interest existed between a verification body and an operator, or an emissions data report that received a positive verification opinion fails an ARB audit, the Executive Officer may set aside the positive verification opinion submitted by the verification body.

(f) Upon request by the Executive Officer the operator shall provide the data used to generate an emissions data report, including all data available to a verifier in the conduct of verification services. ARB may also review the full verification report

given by the verification body to the operator. The full verification report shall be provided to the Executive Officer upon request.

(g) Upon written notification by the Executive Officer, the verification body shall make itself available for a verification services audit.

NOTE: Authority cited: Sections 39600, 39601, 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.

(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.

(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, except as provided in section 95132(b)(1)(F).

      (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 at least two verifiers that have been accredited as lead verifiers, as specified in section 95132(b)(2);
         2. A verification body shall have 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 has a minimum of one million U.S. dollars of professional liability insurance.

      (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. An organization chart that includes the verification body and any related entities.

(E) The applicant shall provide a demonstration that the body has procedures or policies to support staff technical training as it relates to verification.

(F) 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), or (D):

(A) Evidence that the applicant has completed ARB verification training and received a passing score on an exit examination; and,

(B) Evidence that the applicant has acted as project manager or in a lead capacity in one or more of the following greenhouse gas reporting programs:
1. As an approved lead verifier in good standing for the California Climate Action Registry prior to December 1, 2007, having performed at least three verifications by December 31, 2007; or as an acting lead verifier in the California Climate Action Registry, having taken CCAR or other GHG lead verification training and having performed at least three verifications by December 31, 2007; or,
2. As a recognized lead verifier in good standing for the United Kingdom Accreditation System, having performed at least three verifications by December 31, 2007; or,
3. In an organization accredited by a recognized agency in ISO 14065, or ISO 19011, having performed at least three verifications by December 31, 2007; or,

(C) 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 for services performed; or,

    (D)   Evidence that 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 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 field enforcement, or other technical skills necessary to conduct verification.

(4)   The applicant shall take an ARB general verification training course and receive a passing score on an exit examination.

(5)   ***Sector Specific Verifiers.*** The applicant seeking to be accredited as a sector specific verifier as specified in section 95131(a)(2) shall, in addition to meeting the requirements for verifier qualification, take ARB sector specific verification training and receive a passing score on an exit examination.

(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, 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 grant or withhold accreditation for the verification body, lead verifier, or verifier.

(4) The Executive Officer shall issue an Executive Order to grant accreditation to the applicant if the evidence of qualification submitted by the applicant has been found complete and sufficient and the applicant has successfully completed the required training and examination(s).

(5) 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. All ARB approved general or sector 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.

(6) The Executive Officer shall issue an Executive Order to grant accreditation to a verification body if evidence of qualification submitted by the applicant has been found to meet the requirements of section 95132(b)(1).

(7) 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.

(d) *Modification or Revocation of an Executive Order Approving a Verification Body, Lead Verifier, or Verifier.* The Executive Officer may review and, for good cause, modify 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.

(e) *Subcontracting.* The following requirements shall apply to any verification body that elects to subcontract 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 or verification bodies.

(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 verification body or verifier acting as a subcontractor to another verification body shall not further subcontract or outsource verification services for an operator.

(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 operator for which it will provide verification services.

NOTE: Authority cited: Sections 39600, 39601, 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.

(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.

(b) The potential for a conflict of interest shall be deemed to be high where:

(1) The verification body and operator share any management staff or board of directors membership, or any of the management staff of the operator have been employed by the verification body, or vice versa, within the previous three years; or

(2) Within the previous three years, any staff member of the verification body or any related entity has provided to the operator any of the following non-verification services:
    (A) Designing, developing, implementing, or maintaining an inventory or information or data management system for facility greenhouse gases, or, where applicable, electricity transactions;
    (B) Developing greenhouse gas emission factors or other greenhouse gas-related engineering analysis;
    (C) Designing energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;
    (D) Preparing or producing greenhouse gas-related manuals, handbooks, or procedures specifically for the reporting facility;
    (E) Appraisal services of carbon or greenhouse gas liabilities or assets;
    (F) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;
    (G) Managing any health, environment or safety functions;

(H)   Bookkeeping or other services related to the accounting records or financial statements;

(I)   Any service related to information systems, unless those systems will not be part of the verification process;

(J)   Appraisal and valuation services, both tangible and intangible;

(K)   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 shall not be part of the verification process;

(L)   Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

(M)   Any internal audit service that has been outsourced by the operator that relates to the operator's internal accounting controls, financial systems or financial statements, unless the result of those services shall not be part of the verification process;

(N)   Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the operator;

(O)   Any legal services;

(P)   Expert services to the operator or its legal representative for the purpose of advocating the operator's interests in litigation or in a regulatory or administrative proceeding or investigation, unless providing factual testimony.

(3)   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 operator within the last three years, except within the time periods in which the operator is allowed to use the same verification body as specified in sections 95130(a) and 95130(b).

(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 operator 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).

(1)   If a verification body identifies a medium potential for conflict of interest and wishes to provide verification services for the operator, 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 an operator, 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 operator 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) An organizational chart of the verification body and brief description of the verification body and any related entities;

(C) Identification of whether any member of the verification team has previously provided verification services for the operator and, if so, the years in which such verification services were provided;

(D) Identification of whether any member of the verification team or related entity has engaged in any non-verification services of any nature with the operator 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 operator 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 operator's greenhouse gas emissions or the accounting of greenhouse gas emissions or electricity transactions;

2. The nature of past, present or future relationships with the operator including:
   a. Instances when any member of the verification team has performed or intends to perform work for the operator;
   b. Identification of whether work is currently being performed for the operator, and if so, the nature of the work;
   c. How much work was performed for the operator in the last three years, in dollars or percentage of verifier's revenues or gross income;
   d. Whether any member of the verification team has any contracts or other arrangements to perform work for the operator or a related entity;
   e. How much work related to greenhouse gases or electricity transactions the verification team has performed for the operator or related entities in the last three years, in dollars or percentage of the body's and its subcontractors' revenues or gross income.

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.

(E) A list of names of the staff that would perform verification services for the operator, and a description of any instances of personal or family relationships with management or employees of the operator that potentially represent a conflict of interest; and,

(F) Identification of any other circumstances known to the verification body or operator that could result in a conflict of interest.

(f) **Conflict of Interest Determinations.** The Executive Officer shall review the self-evaluation submitted by the verification body and determine whether the verification body is authorized to perform verification services for the operator.

(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 forty-five days of deeming the evaluation information complete, the Executive Officer shall determine whether the verification body is authorized to proceed with verification and shall 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 operator, 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, then 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 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 entering into any contract with the operator for which the body has provided verification services, the verifier shall notify the Executive Officer of the contract and the nature of the work to be performed.

(3)   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.

(4)   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 operator shall be provided 180 days to complete re-verification.

(5)   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, 41511, 38510, and 38530, Health and Safety Code. Reference: Sections 39600, 41511, and 38530, Health and Safety Code.

APPENDIX A

to the Regulation for the Mandatory Reporting
of Greenhouse Gas Emissions

**ARB COMPENDIUM OF EMISSION FACTORS AND METHODS TO SUPPORT
MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS**

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ARB COMPENDIUM OF EMISSION FACTORS AND METHODS TO SUPPORT MANDATORY REPORTING OF GREENHOUSE GAS EMISSIONS

CONTENTS

1. Introduction

The contents of this compendium specify acceptable methods and emission factors that operators must use when preparing greenhouse gas emissions data reports for submission to the California Air Resources Board (ARB), as specified in the ARB Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

2. Unit Conversions

Table 1. Conversion Table		
To Convert From	**To**	**Multiply By**
Grams (g)	Tonnes (metric)	1×10^{-6}
Kilograms (kg)	Tonnes (metric)	1×10^{-3}
Megagrams	Tonnes (metric)	1
Gigagrams	Tonnes (metric)	1×10^{3}
Pounds (lbs)	Tonnes (metric)	4.5359×10^{-4}
Tons (long)	Tonnes (metric)	1.016
Tons (short)	Tonnes (metric)	0.9072
Barrels	Cubic metres (m^3)	0.15898
Cubic feet (ft^3)	Cubic metres (m^3)	0.028317
Liters	Cubic meters (m^3)	1×10^{-3}
Cubic yards	Cubic meters (m^3)	0.76455
Gallons (liquid, US)	Cubic meters (m^3)	3.7854×10^{-3}
Imperial gallon	Cubic meters (m^3)	4.54626×10^{-3}
Joule	Gigajoules (GJ)	1×10^{-9}
Kilojoule	Gigajoules (GJ)	1×10^{-6}
Megajoule	Gigajoules (GJ)	1×10^{-3}
Terajoule (TJ)	Gigajoules (GJ)	1×10^{3}
Btu	Gigajoules (GJ)	1.05506×10^{-6}
Kilocalorie	Gigajoules (GJ)	4.187×10^{-6}
Tonne oil eq. (toe)	Gigajoules (GJ)	41.86
kWh	Gigajoules (GJ)	3.6×10^{-3}
Btu / ft^3	GJ / m^3	3.72589×10^{-5}
Btu / lb	GJ / Tonnes (metric)	2.326×10^{-3}
Lb / ft^3	Tonnes (metric) / m^3	1.60185×10^{-2}
Psi	Bar	0.0689476
Kgf / cm^3 (tech atm)	Bar	0.980665
Atm	Bar	1.01325
Mile	Kilometer	1.6093
Hectares	Acres	2.471
Barrels	Gallons (liquid, US)	42

3. Global Warming Potentials

According to the Intergovernmental Panel on Climate Change (IPCC), the global warming potential (GWP) of a greenhouse gas is defined as the ratio of the time-integrated radiative forcing from the instantaneous release of 1 kilogram (kg) of a trace substance relative to that of 1 kg of a reference gas. The reference gas used is CO_2. The values given below are those reported in the IPCC Second Assessment Report (IPCC 1996). These values are used to be consistent with other statewide and national Greenhouse Gas (GHG) inventories. Operators must use these values when converting emissions of greenhouse gases to carbon dioxide equivalent values (CO_2e) for purposes of estimating *de minimis* or other emissions as specified in this article.

Table 2. Global Warming Potentials (100-Year Time Horizon)	
Gas	**GWP**
CO_2	1
CH_4*	21
N_2O	310
HFC-23	11,700
HFC-32	650
HFC-125	2,800
HFC-134a	1,300
HFC-143a	3,800
HFC-152a	140
HFC-227ea	2,900
HFC-236fa	6,300
HFC-4310mee	1,300
CF_4	6,500
C_2F_6	9,200
C_4F_{10}	7,000
C_6F_{14}	7,400
SF_6	23,900
* The CH_4 GWP includes the direct effects and those indirect effects due to the production of tropospheric ozone and stratospheric water vapor. The indirect effect due to the production of CO_2 is not included.	
Source: IPCC Climate Change 1995: The Science of Climate Change. (1996) Intergovernmental Panel on Climate Change, J.T. Houghton, L.G. Meira Filho, B.A. Callander, N. Harris, A. Kattenberg, and K. Maskell, eds. Cambridge University Press. Cambridge, U.K.	

4. Method for Fuel Use to Carbon Dioxide Emissions Estimations

The following table shows the approximate amount of fuel that, when fully combusted, would result in 25,000 and 2,500 metric tonnes of CO_2 for selected common fuel types.

The 25,000 metric tonne threshold is the level at or above which general stationary sources of combustion are required to report under the regulation. Similarly, the 2,500 metric tonne threshold is the level at or above which electricity generating facilities $\geq$1MW are required to report. This information is provided to give operators a rough estimate of whether or not a given facility falls within the scope of ARB's mandatory reporting program. However, this table alone may not be used to demonstrate that a facility has no reporting obligation.

These tables are based on the ARB accepted emission factors which are set forth in this document. If an operator is combusting multiple fuels types, or is using a fuel type not listed in this table, then the operator must multiply the amount of fuel consumed annually for each fuel type by the ARB provided emission factor and sum the emissions to determine annual CO_2 emissions from stationary combustion.

Table 3. Fuel Amounts Resulting in 25,000 or 2,500 MT of CO_2 by Fuel Type				
Fuel Type	**Fuel Units**	**Kg CO_2/Unit**	**Amount of fuel to produce 25,000 MT CO_2**	**Amount of fuel to produce 2,500 MT CO_2**
Natural Gas (unspecified)	scf	0.05	459,140,464	45,914,046
	MMBtu	53.02	471,520	47,152
LPG (energy use)	Gal	5.79	4,317,757	431,776
Distillate Fuel (#1,2 &4)	Gal	10.14	2,466,011	246,601
Motor Gasoline	Gal	8.80	2,841,174	284,117
Landfill Gas	MMBtu	52.03	480,503	48,050
	scf	0.025[*]	916,301,950	91,630,195
Coal (Unspecified Other Industrial)	Short Ton	2,082.89	12,003	1,200
Jet Fuel	Gal	9.56	2,614,682	261,468
Kerosene	Gal	9.75	2,562,972	256,297
Petroleum Coke	MMBtu	102.04	244,996	24,500
	Short Ton	2530.70	9,879	988
Crude Oil	Gal	10.29	2,430,348	243,035

[*]Note: The emission factor shown includes only the CO_2 emissions from the combustion of landfill gas. It does not include the CO_2 pass-through emissions.

5. Emission Factors

When working with the following emission factor tables the molar mass ratio of carbon dioxide to carbon (CO_2/C) is assumed to be 3.664. Complete oxidation is assumed for all fuels (oxidation factor = 1).

(a) Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors for Stationary Combustion

> The default heat contents specified in Table 4 are provided for use with sections 95125(a) and (b) of the regulation.

> The default carbon dioxide emission factors from stationary combustion on a heat content basis (kg CO_2 / MMBtu) specified in Table 4 and Table 5 are provided for use with sections 95125(a), (c) and (h) of the regulation.

Table 4. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type				
Fuel Type	**Default Carbon Content**	**Default Heat Content**	**Default CO_2 Emission Factor**	**Default CO_2 Emission Factor**
Coal and Coke	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Anthracite	28.26	25.09	2,597.94	103.54
Bituminous	25.49	24.93	2,328.35	93.40
Sub-bituminous	26.48	17.25	1,673.64	97.02
Lignite	26.30	14.21	1,369.32	96.36
Unspecified (Residential/Commercial)	26.00	22.24	2,118.67	95.26
Unspecified (Industrial Coking)	25.56	26.28	2,461.17	93.65
Unspecified (Other Industrial)	25.63	22.18	2,082.89	93.91
Unspecified (Electric Power)	25.76	19.97	1,884.86	94.38
Coke	27.85	24.80	2,530.65	102.04
Natural Gas (By Heat Content)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic ft.**	**kg CO_2 / MMBtu**
975 to 1,000 Btu / Standard cubic foot	14.73	n/a	n/a	53.97
1000 to 1,025 Btu / Std cubic foot	14.43	n/a	n/a	52.87
1025 to 1,050 Btu / Std cubic foot	14.47	n/a	n/a	53.02
1050 to 1,075 Btu / Std cubic foot	14.58	n/a	n/a	53.42
1075 to 1,100 Btu / Std cubic foot	14.65	n/a	n/a	53.68
Greater than 1,100 Btu / Std cubic foot	14.92	n/a	n/a	54.67
Unspecified (Weighted U.S. Average)	14.47	1,027	0.0544	53.02

Table 4. Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type (continued)				
Petroleum Products	**kg C / MMBtu**	**MMBtu / Barrel**	**kg CO_2 / gallon**	**kg CO_2 / MMBtu**
Asphalt & Road Oil	20.62	6.636	11.94	75.55
Aviation Gasoline	18.87	5.048	8.31	69.14
Distillate Fuel Oil (#1, 2 & 4)	19.95	5.825	10.14	73.10
Jet Fuel	19.33	5.670	9.56	70.83
Kerosene	19.72	5.670	9.75	72.25
LPG (energy use)	17.19	3.861	5.79	62.98
Propane	17.20	3.824	5.74	63.02
Ethane	16.25	2.916	4.13	59.54
Isobutane	17.75	4.162	6.44	65.04
n-Butane	17.72	4.328	6.69	64.93
Lubricants	20.24	6.065	10.71	74.16
Motor Gasoline	19.33	5.218	8.80	70.83
Residual Fuel Oil (#5 & 6)	21.49	6.287	11.79	78.74
Crude Oil	20.33	5.800	10.29	74.49
Naphtha (<401 deg. F)	18.14	5.248	8.30	66.46
Natural Gasoline	18.24	4.620	7.35	66.83
Other Oil (>401 deg. F)	19.95	5.825	10.14	73.10
Pentanes Plus	18.24	4.620	7.35	66.83
Petrochemical Feedstocks	19.37	5.428	9.17	70.97
Petroleum Coke	27.85	6.024	14.64	102.04
Still Gas	17.51	6.000	9.17	64.16
Special Naphtha	19.86	5.248	9.09	72.77
Unfinished Oils	20.33	5.825	10.33	74.49
Waxes	19.81	5.537	9.57	72.58
Other Solid Fuels	**kg C / MMBtu**	**MMBtu / Short Ton**	**kg CO_2 / Short Ton**	**kg CO_2 / MMBtu**
Biomass Derived Fuels (Solid). Wood and Wood Waste (12% moisture content) or other solid biomass-derived fuels	25.60	15.38	1,442.62	93.80
Municipal Solid Waste (MSW)	24.74	8.7	788.7	90.65
Biomass-derived Fuels (Gas)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cubic ft.**	**kg CO_2 / MMBtu**
Biogas[*]	28.4	Varies	Varies	104.06

Note: Heat content factors are based on higher heating values (HHV).

[*] The emission factors for biogas include both the CO_2 from combustion and the pass-through CO_2, which are assumed to be in equal proportions.

Table 5. Default Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type for Waste Derived Fuels

Fuel Type	kg CO_2 / MMBtu
Waste Oil	78
Tires	90
Plastics	79
Solvents	78
Impregnated Saw Dust	79
Other Fossil Based Wastes	84
Dried Sewage Sludge	116
Mixed Industrial Waste	88
Municipal Solid Waste	91

Note: Emission factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels.

Source: WBCSD/WRI, *The Cement CO_2 Protocol: CO_2 Accounting and Reporting Standard for the Cement Industry* Calculation Tool (2004), except: Municipal Solid Waste, (from EIA *Voluntary Reporting of Greenhouse Gases Website* http://www.eia.doe.gov/oiaf/1605/coefficients.html (Accessed October 5, 2007))

(b) Methane and Nitrous Oxide Emission Factors for Stationary Combustion

The default methane and nitrous oxide emission factors for stationary combustion in Table 6 are provided for use with section 95125(b) of the regulation. For readability, these emission factors are provided in units of grams/MMBtu, but should be converted to kg/MMBtu (i.e., divided by 1000) when using them in the equations in section 95125(b).

Table 6. Default CH_4 and N_2O Emission Factors from Stationary Combustion by Fuel Type		
Fuel Type	**Default CH_4 Emission Factor (g CH_4/ MMBtu)**	**Default N_2O Emission Factor (g N_2O / MMBtu)**
Asphalt	3.0	0.6
Aviation Gasoline	3.0	0.6
Coal	10.0	1.5
Crude Oil	3.0	0.6
Derived Gases (low Btu gases)	0.3	0.1
Digester Gas	0.9	0.1
Distillate	3.0	0.6
Gasoline	3.0	0.6
Jet Fuel	3.0	0.6
Kerosene	3.0	0.6
Landfill Gas	0.9	0.1
LPG	1.0	0.1
Lubricants	3.0	0.6
MSW	30.0	4.0
Naphtha	3.0	0.6
Natural Gas	0.9	0.1
Natural Gas Liquids	3.0	0.6
Other Biomass	30.0	4.0
Petroleum Coke	3.0	0.6
Propane	1.0	0.1
Refinery Gas	0.9	0.1
Residual Fuel Oil	3.0	0.6
Tires	3.0	0.6
Waste Oil	30.0	4.0
Waxes	3.0	0.6
Wood (Dry)	30.0	4.0
Notes: Heat content factors are based on higher heating values (HHV). Values were converted from LHV to HHV assuming that LHV are 5 percent lower than HHV for solid and liquid fuels and 10 percent lower for gaseous fuels. Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1 g of CH_4/MMBtu.		
Source: Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (2006), Volume 2, Tables 2.2, 2.3, and 2.4.		

(c) Carbon Dioxide Emission Factors for Transportation Fuels

The default carbon dioxide emission factors in Table 7 are provided for use with section 95125(i) of the regulation. These factors may only be used for vehicular emissions and should not be applied to stationary combustion sources.

Table 7. Carbon Dioxide Emission Factors for Transportation Fuels	
Fuel	**kg CO_2/gallon**
Aviation gasoline	8.24
Biodiesel	9.52
CA Low Sulfur Diesel	9.96
CA Reformulated gasoline, 5.7% ethanol	8.55
Crude Oil	10.14
Non-CA Diesel/Diesel No.2	10.05
Ethanol (E85)	6.10
Fischer Tropsch Diesel	9.13
Jet Fuel, Kerosene (Jet A or A-1)	9.47
Jet Fuel, Naphtha (Jet B)	9.24
Kerosene	9.67
Liquefied Natural Gas (LNG)	4.37
Liquefied Petroleum Gas (LPG)	5.92
Methanol	4.10
Motor Gasoline (Non CA and off-road)	8.78
Propane	5.67
Residual Oil	11.67
Fuels With Other Units Of Measure	
Natural Gas (CNG) per therm	5.28
Natural Gas (CNG) per gasoline gallon equivalent	6.86
Hydrogen per kg	0.00
Note: Emission factors are based on complete combustion and high heating value (HHV).	
Source: California Energy Commission*, Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999* (November 2002); Energy Information Administration*, Emissions of Greenhouse Gases in the United States 2000*, (2001), Table B1, page 140, see http://www.eia.doe.gov/oiaf/1605/ggrpt; propane and butane emission factors and fractions oxidized from U.S. Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors, AP- 42*, Fifth Edition, see http://www.epa.gov/ttn/chief/ap42/index.html. Methanol emission factor is calculated from the properties of the pure compounds; the fraction oxidized is assumed to be the same as for other liquid fuel.	

(d) Methane and Nitrous Oxide Emission Factors for On-Road Mobile Sources

The default methane and nitrous oxide emission factors in Table 8 are provided for use with section 95125(i) of the regulation.

Table 8. Methane and Nitrous Oxide Emission Factors for Mobile Sources by Vehicle and Fuel Type		
Vehicle Types/Model Years	**CH_4 (g/mile)**	**N_2O (g/mile)**
Passenger Cars - Gasoline		
Model Year 1984-1993 and older	0.0704	0.0647
Model Year 1994	0.0531	0.0560
Model Year 1995	0.0358	0.0473
Model Year 1996	0.0272	0.0426
Model Year 1997	0.0268	0.0422
Model Year 1998	0.0249	0.0393
Model Year 1999	0.0216	0.0337
Model Year 2000	0.0178	0.0273
Model Year 2001	0.0110	0.0158
Model Year 2002	0.0107	0.0153
Model Year 2003	0.0114	0.0135
Model Year 2004	0.0145	0.0083
Model Year 2005– present	0.0147	0.0079
Passenger Cars - Alternative Fuels and Diesel		
Methanol	0.018	0.067
CNG	0.737	0.050
LPG	0.037	0.067
Ethanol	0.055	0.067
Diesel Model Year 1960-1982	0.0006	0.0012
Diesel Model Year 1983-present	0.0005	0.0010
Light Duty Truck (Vans, Pickup Trucks, SUVs) Gasoline		
Model Year 1987-1993 and older	0.0813	0.1035
Model Year 1994	0.0646	0.0982
Model Year 1995	0.0517	0.0908
Model Year 1996	0.0452	0.0871
Model Year 1997	0.0452	0.0871
Model Year 1998	0.0391	0.0728
Model Year 1999	0.0321	0.0564
Model Year 2000	0.0346	0.0621
Model Year 2001	0.0151	0.0164
Model Year 2002	0.0178	0.0228
Model Year 2003	0.0155	0.0114
Model Year 2004	0.0152	0.0132
Model Year 2005– present	0.0157	0.0101
Source: Gasoline vehicle factors from EPA Climate Leader, Mobile Combustion Guidance (2008) based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2005 (2007)*. Diesel vehicle factors based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2005 (2007)*, Annex 3.2, Table A-99. Alternative fuel vehicle factors based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2005 (2007)*, Annex 3.2, Table A-100.		

Table 8. Methane and Nitrous Oxide Emission Factors for Mobile Sources by Vehicle and Fuel Type (continued)

Light Duty Truck - Alternative Fuels and Diesel	CH$_4$ (g/mile)	N$_2$O (g/mile)
Methanol	0.018	0.067
CNG	0.737	0.050
LPG	0.037	0.067
Ethanol	0.055	0.067
Diesel Model Year 1960-1982	0.0011	0.0017
Diesel Model Year 1983-1995	0.0009	0.0014
Diesel Model Year 1996-present	0.0010	0.0015
Heavy-Duty Vehicle - Gasoline		
Model Year 1985 -1986 and older	0.4090	0.0515
Model Year 1987	0.3675	0.0849
Model Year 1988-1989	0.3492	0.0933
Model Year 1990-1995	0.3246	0.1142
Model Year 1996	0.1278	0.1680
Model Year 1997	0.0924	0.1726
Model Year 1998	0.0641	0.1693
Model Year 1999	0.0578	0.1435
Model Year 2000	0.0493	0.1092
Model Year 2001	0.0528	0.1235
Model Year 2002	0.0546	0.1307
Model Year 2003	0.0533	0.1240
Model Year 2004	0.0341	0.0285
Model Year 2005-present	0.0326	0.0177
Heavy Duty Trucks - Diesel and Alternative Fuels		
Methanol	0.066	0.175
CNG	1.966	0.175
LNG	1.966	0.175
LPG	0.066	0.175
Ethanol	0.197	0.175
Diesel All Model Years	0.0051	0.0048
Motorcycles		
Model Year 1996 and older	0.0899	0.0887
Model Year 1996-present	0.0672	0.0669

Source: Gasoline vehicle factors from EPA Climate Leader, Mobile Combustion Guidance (2008) based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2005 (2007)*. Diesel vehicle factors based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2005 (2007)*, Annex 3.2, Table A-99. Alternative fuel vehicle factors based on U.S. EPA, *Inventory of U.S. Greenhouse Gas Emission and Sinks: 1990-2005 (2007)*, Annex 3.2, Table A-100.

(e) Fugitive Carbon Dioxide Emission Factor from Geothermal Power Plants

The default carbon dioxide emission factor for geothermal power plants given in Table 9 is provided for use with section 95111(i) of the regulation.

Table 9. Default Fugitive Carbon Dioxide Emission Factor from Geothermal Power Plants	
Fuel Type	**kg CO_2 / MMBtu**
Geothermal	7.53
Source: Energy Information Administration, *Electric Power Annual with data for 2005*, carbon dioxide uncontrolled emission factors website see http://www.eia.doe.gov/cneaf/electricity/epa/epata3.html (Accessed 10/9/07)	

(f) Fugitive Emission Factors for Coal Storage

The emission factors for fugitive methane emissions from coal storage in Table 10 are derived from the U.S. EPA Coal Bed Methane Emissions Estimates Database. These factors must be applied as indicated in section 95125(j) of the regulation.

Table 10. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH_4 ft^3 per Short Ton)			
Coal Origin		**Coal Mine Type**	
Coal Basin	**States**	**Surface Post-Mining Factors**	**Underground Post-Mining Factors**
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	19.3	45.0
Central Appalachia (WV)	Tennessee, West Virginia South	8.1	44.5
Central Appalachia (VA)	Virginia	8.1	129.7
Central Appalachia (E KY)	East Kentucky	8.1	20.0
Warrior	Alabama, Mississippi	10.0	86.7
Illinois	Illinois, Indiana, Kentucky West	11.1	20.9
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	10.8	63.8
Rockies (Uinta Basin)		5.2	32.3
Rockies (San Juan Basin)		2.4	34.1
Rockies (Green River Basin)		10.8	80.3
Rockies (Raton Basin)		10.8	41.6
N. Great Plains	Montana, North Dakota, Wyoming	1.8	5.1
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	11.1	20.9
West Interior (Arkoma Basin)		24.2	107.6
West Interior (Gulf Coast Basin)		10.8	41.6
Northwest (AK)	Alaska	1.8	52.0
Northwest (WA)	Washington	1.8	18.9
Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks:1990 – 2005* April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH4 Emission Factors (ft^3 per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.			

(g) Coke Burn Rate Material Balance and Conversion Factors

The coke burn rate material balance and conversion factors given in Table 11 are provided for use with section 95113(b)(1)(A) of the regulation.

Table 11. Coke burn rate material balance and conversion factors		
	(kg min)/(hr dscm %)	(lb min)/(hr dscf %)
K_1	0.2982	0.0186
K_2	2.0880	0.1303
K_3	0.0994	0.0062
Source: US EPA Title 40 CFR 63.1564		

(h) Methane and Nitrous Oxide Emission Factors for Wastewater Treatment

The method to derive an emission factor for fugitive methane and nitrous oxide emissions from wastewater treatment specified below is based on 2006 IPCC guidelines. This method is provided for use with section 95113(c)(1)(A)-(B) of the regulation.

Table 12. Default MCF Values for Industrial Wastewater			
Type of Treatment and Discharge Pathway or System	**Comments**	**MCF**	**Range**
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this is not considered here	0.1	0 - 0.2
Treated			
Aerobic treatment plant	Well maintained, some CH4 may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH_4 recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 meters	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 meters	0.8	0.8 – 1.0
Source: Intergovernmental Panel on Climate Change, *2006 IPCC Guidelines for National Greenhouse Gas Inventories* (2006), Volume 5, Waste, Chapter 6: Wastewater Treatment and Discharge. Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Buendia L., Miwa K., Ngara T. and Tanabe K. (eds).			

MCF = methane correction factor – the fraction of waste treated anaerobically

B =CH_4 generation capacity (kg CH_4/kg COD)
Default factor = 0.25 kg CH_4/kg COD

COD = chemical oxygen demand (kg COD/m^3)

Emission factor for N_2O from discharged wastewater
EF_{N2O} = 0.005 kg N_2O-N/kg-N

(i) Emission Factors for Oil/Water Separators

Use Table 13 to derive emission factors for oil/water separators

Table 13. Emission Factors for Oil/Water Separators	
Separator Type	Emission factor $(EF_{sep})^1$ kg NMHC/m^3 wastewater treated
Gravity type - uncovered	1.11e-01
Gravity type - covered	3.30e-03
Gravity type – covered and connected to destruction device	0
DAF^2 of IAF^3 - uncovered	4.00e-03^4
DAF or IAF - covered	1.20e-04^4
DAF or Iaf – covered and connected to a destruction device	0
Source: Air pollutant emission estimation methods for E-PRTR reporting by refineries, CONCAWE, Brussels, April 2007, report no. 3/07	

1. EFs do not include ethane
2. DAF = dissolved air flotation type
3. IAF = induced air flotation device
4. EFs for these types of separators apply where they are installed as secondary treatment systems

(j) Gas Service Components Fugitive Emission Factors

The information presented in Table 14 is provided for use with section 95113(c)(4) as part of the method to determine fugitive methane emissions from fuel gas systems.

Table 14. Gas Service Components Fugitive Emissions				
Component Type / Service Type	**Default Zero Factor (kg/hr)**	**Correlation Equation (kg/hr)**	**Pegged Factor (kg/hr)**	
			10,000 ppmv	**100,000 ppmv**
	Zf_{i0}	σ_i and β_i	**(SV > 9,999) $PF_{iP\text{-}10}$**	**(SV> 99,999) $PF_{iP\text{-}100}$**
Valves (1)	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064	0.138
Pump seals (2)	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089	0.610
Others (3)	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082	0.138
Connectors (4)	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030	0.034
Flanges (5)	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095	0.095
Open-ended lines (6)	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033	0.082
Source: California Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities, February 1999, California Air Pollution Control Officers Association (CAPCOA) and California Air Resources Board				

6. Method for Calculating Emissions of High Global Warming Potential Compounds

Provided below is the fugitive SF_6 emissions calculation methodology created by the U.S. EPA SF_6 Emission Reduction Partnership for Electric Power Systems. Operators shall use this approach or a service log for estimating fugitive emissions of high global warming potential compounds, including SF_6, HFCs, and PFCs, as specified in sections 95111(f)-(g) of the regulation. The reporting form that follows the method below is for illustrative purposes. Pounds shall be converted to kilograms for purposes of reporting.

SF6 EMISSIONS INVENTORY REPORTING METHOD AND FORM

This worksheet is based on the **mass-balance method**. The mass-balance method works by tracking and systematically accounting for all operator uses of SF_6 during the reporting year. The quantity of SF_6 that cannot be accounted for is then assumed to have been emitted to the atmosphere. The method has four subcalculations (A-D), a final total (E), and an optional emission rate calculation (F) as follows:

A. **Change in Inventory**. This is the difference between the quantity of SF_6 in storage at the beginning of the year and the quantity in storage at the end of the year. The "quantity in storage" includes SF_6 gas contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not refer to SF_6 gas held in operating equipment. The change in inventory will be negative if the quantity of SF_6 in storage increases over the course of the year.

B. **Purchases/Acquisitions of SF_6**. This is the sum of all the SF_6 acquired from other entities during the year either in storage containers or in equipment.

C. **Sales/Disbursements of SF_6**. This is the sum of all the SF_6 sold or otherwise disbursed to other entities during the year either in storage containers or in equipment.

D. **Change in Total Nameplate Capacity of Equipment**. This is the net increase in the total volume of SF_6-using equipment during the year. Note that "total nameplate capacity" refers to the full and proper charge of the equipment rather than to the actual charge, which may reflect leakage. This term accounts for the fact that if new equipment is purchased, the SF_6 that is used to charge that new equipment should not be counted as an emission. On the other hand, it also accounts for the fact that if the amount of SF_6 recovered from retiring equipment is less than the nameplate capacity, then the difference between the nameplate capacity and the recovered amount has been emitted. This quantity will be negative if the retiring equipment has a total nameplate capacity larger than the total nameplate capacity of the new equipment.

E. **Total Annual Emissions**. This is the total amount of SF_6 emitted over the course of the year, based on the information provided above. The amount is presented both in pounds of SF_6 and in metric tonnes of CO_2-equivalent, that is, the quantity of carbon dioxide emissions that would have the same impact on the climate as the quantity of SF_6 emitted. Because SF_6 has 23,900 times the ability of carbon dioxide to trap heat in the atmosphere on a pound-for-pound basis, 1 pound of SF_6 is equivalent to nearly 11 metric tonnes of carbon dioxide.

F. **Emission Rate (optional)**. By providing the total nameplate capacity of all the electrical equipment in your facility at the end of the year, you can obtain an estimate of the emission rate of your facility's equipment (in percent per year).
The emission rate is equal to the total annual emissions divided by the total nameplate capacity.

SF$_6$ Emissions Reduction Partnership for Electric Power Systems

Annual Reporting Form

Name:		Company Name:	
Title:		Report Year:	
Phone:		Date Completed:	

Decrease in Inventory (SF$_6$ contained in cylinders, <u>not</u> electrical equipment)

Inventory (in cylinders, **not** equipment)	AMOUNT (lbs.)	Comments
1. Beginning of Year		
2. End of Year		
A. Decrease in Inventory (1 - 2)	-	

Purchases/Acquisitions of SF$_6$

	AMOUNT (lbs.)	Comments
3. SF$_6$ purchased from producers or distributors in cylinders		
4. SF$_6$ provided by equipment manufacturers with/inside equipment		
5. SF$_6$ returned to the site after off-site recycling		
B. Total Purchases/Acquisitions (3+4+5)	-	

Sales/Disbursements of SF$_6$

	AMOUNT (lbs.)	Comments
6. Sales of SF$_6$ to other entities, including gas left in equipment that is sold		
7. Returns of SF$_6$ to supplier		
8. SF$_6$ sent to destruction facilities		
9. SF$_6$ sent off-site for recycling		
C. Total Sales/Disbursements (6+7+8+9)	-	

Increase in Nameplate Capacity

	AMOUNT (lbs.)	Comments
10. Total nameplate capacity (proper full charge) of <u>new</u> equipment		
11. Total nameplate capacity (proper full charge) of <u>retired</u> or <u>sold</u> equipment		
D. Increase in Capacity (10 - 11)	-	

Total Annual Emissions

	lbs. SF$_6$	kgs. SF6	Tonnes CO$_2$ equiv.
E. Total Emissions (A+B-C-D) (lbs.)	-	-	-

Emission Rate (optional)

	AMOUNT (lbs.)	Comments
Total Nameplate Capacity at End of Year		
	PERCENT (%)	
F. Emission Rate (Emissions/Capacity)	-	