PUBLIC REVIEW DRAFT

Albuquerque Air Quality Division
Greenhouse Gas Mandatory Emissions Reporting
Emissions Quantification Procedures
For 20.11.47 NMAC and 20.11.48 NMAC

Emissions years: 2010 and subsequent years

CONTENTS

PART 1: GENERAL REPORTING INSTRUCTIONS:

These guidelines specify acceptable methods and emission factors that operators must use when preparing greenhouse gas (GHG) emissions data reports for submission to the Albuquerque Air Quality Division, as specified by 20.11.47 NMAC, *Emissions Inventory Requirements*, and 20.11.48 NMAC, *Greenhouse Gas Emissions Reporting*.

20.11.48 NMAC

Note that for reporting year 2009, direct emissions of CO_2 from applicable sources as well as indirect GHG from electricity, steam heat purchased for and consumed at facility, are required to be reported under the Albuquerque - Bernalillo County Air Quality Control Board's *Greenhouse Gas Emissions Reporting* rule, 20.11.48 NMAC. For reporting year 2010, and each year thereafter, direct emissions of all GHG as well as indirect GHG emissions from electricity, steam and heat purchased for and consumed at facility, are required to be reported. Any other reasonable emissions information requests from the City of Albuquerque must also be reported. Direct emissions from on-road and nonroad motor vehicles are excluded from this requirement.

Per 20.11.48.200 NMAC, The owner or operator of the following facilities shall report GHG emissions to the department: 1). a facility at which the sum of the nameplate capacity of all electrical generating units is equal to or greater than 25 megawatts of electricity; 2). a petroleum refining facility with a North American industry classification system code of 32411; and 3). a cement manufacturing facility with a North American industry classification system code 32731.

Owners or operators that are not required by 20.11.48 NMAC or another board regulation to report GHG emissions may report voluntarily. Owners or operators that are required by 20.11.48 NMAC to report GHG emissions may as an alternative register and verify their GHG emissions with The Climate Registry or the California climate action registry. Compliance with Subsection C of 20.11.48.200 NMAC shall constitute compliance with GHG emissions reporting for the GHG emissions reporting year if: 1). the GHG emissions report complies with all other requirements of 20.11.48 NMAC; and 2). the owner or operator has provided the department with access to the information required by 20.11.48 NMAC.

20.11.47 NMAC

20.11.47.14 NMAC applies to the owner or operator of every stationary source, located within Bernalillo county that: 1). has an active permit issued pursuant to 20.11.41 NMAC, *Authority to Construct*, or 20.11.42 NMAC, *Operating Permits*; or 2). is required to file a source registration pursuant to 20.11.40 NMAC, *Source Registration*.

Owners and operators choosing to voluntarily report GHG emissions through The Climate Registry will be deemed in compliance with either 20.11.48 NMAC or

20.11.47 NMAC as long as they comply with the applicable requirements of The Climate Registry and Subsection C of 20.11.48.200 NMAC. Please notify us in advance of your reporting deadline if you intend to report GHG emissions to The Climate Registry.

Table 1.1 Source Specific Method(s)

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95110	Portland Cement Plants	5-10
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GHG source categories not specifically referenced in Table 1.1 have the discretion as outlined in 95117(a)(3) to use industry specific methods to calculate process vented and non routine emissions, including vented and fugitive CO_2 and methane [2010 and subsequent years], emissions. However, for combustion units at these sources, utilize combustion calculations and report GHG emissions as described in 95115 or 95116, as appropriate. Landfill owners and operators subject to GHG reporting are encouraged to report emissions using one or more of the following methods: *Current MSW Industry Position and State of the Practice on LFG Destruction Efficiency in Flares, Turbines, and Engines* Presented to: Solid Waste Industry for Climate Solutions (SWICS), by SCS Engineers, July 2007; EPA's Landfill Gas Emissions Model (LandGEM); and/or California's Climate Action Registry (CCAR) Local Government Protocol that includes methane fugitive emission calculation methods.

Sources reporting greenhouse gas emissions under 20.11.48.201.B NMAC must include "indirect GHG emissions from all electricity, steam, and heat purchased for and consumed at the facility". When conducting an emissions inventory of your facility please be cognizant that you must also include equipment that emits GHG that is not specifically spelled out in your permit (e.g. pneumatic devices at oil and gas facilities). Reporting of GHGs emitted by mobile sources is not required by this regulation.

Our reporting rule also provides for simplified and limited documentation of emissions that collectively account for five percent or less of total facility emissions, expressed as carbon dioxide. We're open to the submittal of alternative methods not contained herein for such sources. Please be sure to include supporting documentation to support your emission calculations. We anticipate getting familiar with such sources as we progress through the annual reporting cycles.

Each GHG report shall also include GHG emissions occurring during regular operation, maintenance, start-ups, shutdowns, upsets and malfunctions. GHG emissions data from combustion, vented and fugitive units can be aggregated at the facility level. For example, all combustion sources can be reported in aggregate at the facility level. Vented or fugitive GHG emission sources may also be aggregated by category type at the facility level. If unit level data are required by the reporting mechanism (e.g. current spreadsheets or new database), reporters are encouraged to attribute aggregate facility totals by emission type (e.g. combustion) to individual units using best available methods.

Please include the following data as an electronic attachment with your emissions inventory submittal:

- Facility GHG emissions total(s) as follows: GHG emissions in carbon dioxide equivalent CO_2e, CO_2 combustion process, vented and fugitive emissions, and methane combustion process, vented and fugitive emissions;
- Detailed GHG emission calculations and calculation methodology [e.g. 95125(g)] used for each subject item type (e.g. combustion, vented and fugitive);
- Fuel carbon content by weight percent for each fuel type used at the facility;
- Vented and fugitive methane and CO_2 emissions by equipment type;
- Indirect emissions for sources reporting 2009 emissions pursuant to 20.11.48.201.B NMAC.

PART 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 shall include the following information in the emissions data report for each report year.

(1) Total Emissions:

(A) Total CO_2 emissions (metric tonnes) [2008 and subsequent years];
(B) Total CH_4 emissions (metric tonnes) [2010 and subsequent years]; and
(C) Total N_2O emissions (metric tonnes) [2010 and subsequent years].

(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 tonnes 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 (20 short hundredweight, 2000 pounds or 0.907 metric ton) 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 95.110a(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) [2010 and subsequent years]; and
(F) N_2O emissions by fuel type (metric tonnes) [2010 and subsequent years].

(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 [2010 and subsequent years] from coal storage (metric tonnes).

(5) Indirect energy usage [2009 and subsequent years] including:
(A) Electricity purchases from each electricity provider (kwh); and
(B) Steam, heat and cooling purchases from each energy provider (Btu).

(b) Calculation of CO_2 [2008 and subsequent years], **N_2O** [2010 and subsequent years]**, *and CH_4 Emissions*** [2010 and subsequent years]***.*** 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) N_2O and CH_4 emissions. Operators of cement plants shall total CH_4 emissions from fuel combustion as specified in Section 95125(b).

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

(4) Fugitive Emissions. Operators of cement plants shall calculate fugitive CH_4 emissions from coal fuel storage piles as specified in Section 95125(i).

(5) 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).

(6) 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.

(c) Process CO_2 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

$$CO_2 \text{ Emissions (metric tonnes)} = [(Cli) \times (EF_{Cli})] + [(CKD) \times (EF_{CKD})]$$

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.

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

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

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

Where:

EF_{CKD} = CKD Emission Factor

EF_{Cli} = Clinker Emission Factor

d = CKD Calcination Rate

Plant-specific CKD Calcination Rate

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

Where:

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

$fCO_{2\,RM}$ = 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 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(a), or Section 95125(d), or Section 95125 (h).

(8) Co-Firing of Fuels: Operators of cement plants that co-fire more than one fossil fuel shall calculate CO_2 emissions separately for each fuel type using methods provided in Section 95110(d) 1-7 and 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

$$\text{CO}_2\ \text{emissions} = \frac{\text{Direct CO}_2\ \text{emissions from cement manufacturing}}{\begin{pmatrix}\text{Own clinker}\\ \text{consumed or}\\ \text{added to stock}\end{pmatrix} + \begin{pmatrix}\text{Own clinker}\\ \text{sold directly}\end{pmatrix} + \begin{pmatrix}\text{gypsum, limestone,}\\ \text{CKD \& clinker}\\ \text{substitutes consumed}\\ \text{for blending}\end{pmatrix} + \begin{pmatrix}\text{cement}\\ \text{substitutes}\end{pmatrix}}$$

(2) CO_2 Emissions per metric tonne of Clinker

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

95111. Data Requirements and Calculation Methods for Electricity Generating Facilities.

(a) Electricity Generating Facilities. The operator of an electricity generating facility shall include the following information in the GHG emissions data report for each report year and shall meet the requirements specified in Sections 95111(c)-(g) as applicable to the facility when calculating emissions for inclusion in the report.

(1) For each facility, operators shall include:

(A) Air quality permit number(s), 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 [MMBtu per unit 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)(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) if the operator elects to calculate CO_2 emissions using methods defined in Section 95125(d);

(E) CO_2 [2008 and subsequent years], N_2O [2010 and subsequent years], and CH_4 [2010 and subsequent years] 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 geothermal 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; and

(K) For facilities located inside Bernalillo County, 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 bus bar. 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, 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; and

(C) CO_2 [2008 and subsequent years], N_2O [2010 and subsequent years], and CH_4 [2010 and subsequent years] emissions from fuel combustion in metric tonnes as specified in Section 95111(c)-(d).

(D) For units of facilities located inside Bernalillo County, 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 meet the requirements of Section 95112.

(b) [Reserved]

(c) Calculation of CO_2 Emissions from Stationary Combustion Excluding Emergency Generators and Fire Fighting Equipment operating less than 500 hours per Calendar Year. Operators of electricity 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 Section 95125(e) or 95125(g).

(5) Landfill Gas or Biogas. If a facility combusts landfill gas or biogas from 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 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 and does not have appropriate devices to measure CO_2 concentrations and flue gas flow rates, the operator shall use methods 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 95125(c)-(e) specified by fuel type in Sections 95111(c)(1)-(4). Operators who have the option in these procedures 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 CO_2 emissions 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 (a), (c)-(e) and (h)(1) 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 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 [2010 and subsequent years] ***and CH_4*** [2010 and subsequent years] ***from Stationary Combustion Excluding Emergency Generators and Fire Fighting Equipment Operating less than 500 hours per Calendar Year*** [2010 and subsequent years]***.*** Operators of generating facilities, retail providers, and marketers shall use the methodologies provided in Section 95125(b) to calculate 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; and
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; and
Heat = Heat taken from geothermal steam and/or fluid, MMBtu per year; or

(2) Operators of geothermal generating facilities may elect to calculate CO_2 emissions using AQD approved source specific emission factors derived from tests conducted at least annually under the supervision of AQD. Upon approval of a test plan by AQD, 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 AQD, the operator shall use the method specified above in Section 95111(f)(1).

(j) Calculation of Fugitive CH_4 Emissions [2010 and subsequent years]**.** 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(i).

Note: The coal methane post-mining fugitive emission factors found in Table 10 of Appendix A are for coal storage and handling prior to combustion at the power plant. They are basin specific and reflect about 33% of the in-situ Methane content found in the coal.

95112. Data Requirements and Calculation Methods for Cogeneration Facilities.

(a) Greenhouse Gas Emissions Data Report. The operator of a cogeneration facility shall include the following information in the greenhouse gas emissions data report for each report year. The operator of a cogeneration facility with nameplate generating capacity less than 10 megawatts 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; and

(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);
   1. Name of retail provider;

(B) Electricity sold or provided directly to end-users (MWh);
   1. Customer's NAICS code; and

(C) Electricity consumed on-site for each report year (MWh).

(4) Thermal Energy Production:

(A) Total useful output (MMBtu);

(B) Amount of thermal energy sold or provided to cogeneration thermal host (MMBtu);
   1. Customer's NAICS code;

(C) Amount of thermal energy from the cogeneration system consumed on-site for processes other than the cogeneration system for each report year (MMBtu);

(D) Input steam to steam turbine, if measured (MMBtu);

(E) Output of heat recovery steam generator (MMBtu);

(F) Fuel fired for supplemental firing in the duct burner of the HRSG (MMBtu); and

(G) Efficiency of thermal energy production, if known.

(5) Distributed Emissions:

(A) Distributed emissions to thermal energy production (metric tonnes CO_2);

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

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

(b) Calculation of CO_2 [2008 and subsequent years] ***N_20,*** [2010 and subsequent years]***, and CH_4 Emissions*** [2010 and subsequent years]***.*** 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)-(f), if applicable, using the methodologies designated in the respective sections.

(3) N_20 and CH_4 emissions from stationary combustion using the methodologies provided in Section 95125(b).

(4) [Reserved]

(5) 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 and report 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 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*

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

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; and
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; and
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

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

Electricity Generation

$$E_P = E_T - E_H - E_M$$

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 x 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; and
E_P = Distributed emissions to electricity generation, metric tonnes CO_2.

1. Facility-Specific Electricity Generation Efficiency Value:

$$e_P = \frac{P}{(F + H_e)}$$

Where:
e_P = Efficiency of electricity generation;
P = Net power generated in the report year, MMBtu; and
H_{st} = Input steam to steam turbine, MMBtu.

2. Emissions Assigned to Manufacturing Process:

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

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; and
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

$$He = \frac{HRSG}{HRSG_{EF}} - F$$

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; and
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 then set to 0.

(c) Abbreviated Greenhouse Gas Emissions Data Report. The operator of a cogeneration facility with nameplate generating capacity <10 MW electing 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) AQD designated facility identification number (ID contained in NSR or Title V permit), 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 (scf, therms, MMBtu, gallons, tons or bone dry tons);
(C) Cogeneration system information as specified in Section 95112 (a)(2);

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

(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 in the applicable AQD NSR or Title V permit, 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; and

(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 [2008 and subsequent years] ***N_2O, and CH_4 Emissions*** [2010 and subsequent years]***.*** 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 with nameplate generating capacity less than 10 megawatts (MW) 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).

95113. Data Requirements and Calculation Methods for Petroleum Refineries.

(a) Greenhouse Gas Emissions Data Report. The operator of a petroleum refinery that emits greater than or equal to 25,000 metric tonnes per year of CO_2 from the combination of stationary combustion and process sources 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 (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), (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 tones).

(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 by 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.

(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 mole fractions derived from approved source tests as specified in Section 95113(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(j)-(k).

(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 emissions monitoring system as specified in Section 95125(g)(7). 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)(A), (B) and (C). Hourly coke burn rate shall be calculated as shown below:

$$CR = K_1Q_r(\%CO_2 + \%CO) + K_2Q_a - K_3Q_r[\%CO/2 + \%CO_2 + \%O_2] + K_3Q_{oxy}(\%O_{xy})$$

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); and
$\%O_{xy}$ = 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:

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

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; and
$\%O_2$ = 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; and
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; and
0.001 = conversion factor – kg to metric tones

(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.

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

Where:
CO_2 = CO_2 emissions (metric tonnes/yr);
CC_{irc} = average catalyst regeneration rate (tonnes/hr);
CF_{spent} = carbon fraction on spent catalyst;
CF_{regen} = carbon fraction on regenerated catalyst (default = 0);
H = hours regenerator was operational (hr/yr); and
3.664 = conversion factor – carbon to carbon dioxide

(3) Process Vents

(A) The operator shall calculate and report process emissions of CO_2 [2008 and subsequent years], N_2O [2010 and subsequent years], and CH_4 [2010 and subsequent years] from process vents using the method shown below. Process emissions calculated and reported using other methods specified in this procedure 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);
$_x = CO_{2;}$
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 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; and
0.001 = conversion factor – kg to metric tonnes.

(4) Asphalt Production

(A) The operator shall calculate and report CO_2 [2008 and subsequent years] and CH_4 [2010 and subsequent years] emissions resulting from asphalt blowing activities using the method specified below:

$$CH_4 = (M_A * EF * MW_{CH4} / MCV) (1\text{-}DE * 0.0001)$$

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 centigrade and 1 atmosphere;
DE = control measure destruction efficiency (DE = 98% expressed as 0.98); and
0.001 conversion factor – kg to metric tonnes

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

Where:
CO_2 = CO_2 emissions (metric tonnes/yr);
M_A = mass of asphalt blown (10^3 bbl/yr);
EF = default emission factor (2,555 scf $CH_4/10^3$ bbl);
MW_{CH4} = CH_4 molecular weight (16 kg/kg-mole);
MVC = molar volume conversion factor (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);
DE = control measure destruction efficiency (default = 98% expressed as 0.98);
2.743 = CH_4 to CO_2 conversion factor; and
0.001 = conversion factor – kg to metric tonnes

(5) Sulfur Recovery

(A) Operators shall calculate 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°C and 1 atmosphere or 836 scf/kg-mole, for STP of 60°F, and 1 atmosphere);
MF = mole fraction of CO_2 in sour gas; MF = 0.20; and
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 a source specific mole fraction of CO_2 in the sour gas, derived from source tests conducted at least once per calendar year following an AQD approved test protocol. Upon AQD approval of a source test plan, the source test procedures in that plan shall be repeated in subsequent years to update the source specific CO_2 mole fractions annually. In the absence of source specific CO_2 mole fractions approved by AQD, the operator shall use the default value provided in Section 95113(b)(5)(A).

(c) Calculation of Fugitive Emissions [2010 and subsequent years]. 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; and
0.01= 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; and
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; and
0.01 = conversion factor – kg to metric tonnes.

(3) Storage Tanks

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) or using *AP 42, Fifth Edition, Volume I Chapter 7: Liquid Storage Tanks*. 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 AQD approved sampling and analysis methodology.

(4) Equipment Fugitive Emissions

The operator shall calculate and report CH_4 fugitive emissions for all refinery gas service components using an appropriate emissions estimate methodology.

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

(1) The operator shall calculate and report CO_2 [2008 and subsequent years] N_2O [2010 and subsequent years], and CH_4 [2010 and subsequent years] emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in 95113(a)(1) and (9).

(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 the method specified below:

(A) The operator 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);
CF_{NMHC} = conversion factor – NMHC to carbon ($CF_{NMHC} = 0.6$);
3.664 = conversion factor – carbon to carbon dioxide; and
0.001 = conversion factor – carbon to carbon dioxide

(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 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, for STP of 60°F, and 1 atmosphere);
3.664 = conversion factor – carbon to carbon dioxide; and
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 with an uncertainty of no more than ± 7.5%.

95114. Data Requirements and Calculation Methods for Hydrogen Plants.

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

(1) Fuel and Feedstock Consumption. Fuel consumption and feedstock consumption in the report year by 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 [2010 and subsequent years] **and N_2O** [2010 and subsequent years]***.*** The operator shall calculate and report CH_4 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 resulting from flaring (if these emissions are not calculated using other methods specified in this procedure) using the methods specified in Section 95113(d), (metric tonnes).

(6) Transferred CO_2 and CO. The operator shall calculate 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 procedure 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. 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(j)-(k).

(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 Emissions 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; and
0.001 = conversion factor – kg to metric tonnes.

Where:
CO_2 = carbon dioxide process and stationary combustion emissions – metric tonnes/year;
n = days of operation per reporting period;
F = fuel consumption rate (scf/day);
CF_F = carbon content of fuel (kg C/scf fuel);
FS = feedstock consumption rate (scf/day);
CF_{FS} = carbon content of feedstock (kg C/scf feedstock);
S = carbon accounted for elsewhere (kg C/day);
3.664 = conversion factor – carbon to carbon dioxide; and
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 procedures (for example: uncovered 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 procedure). 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.

$$CO_2 = \sum_{1}^{n} [(FSR * CF) - S] * 3.664 * 0.001$$

Where:
CO_2 = carbon dioxide emissions (metric tonnes/yr);
N = number of operational days;
X = number of feedstocks;
FSR = feedstock supply rate (scf/day);
CF = carbon content of feedstock (kg C/scf fuel);
S = carbon accounted for elsewhere (kg C/day);

3.664 = conversion factor – carbon to carbon dioxide; and
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 procedures (for example: uncovered 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 procedure). 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.

95115. Data Requirements and Calculation Methods for General Stationary Combustion Facilities, not including Oil and Gas.

(a) Greenhouse Gas Emissions data report. The operator of any facility that emits CO_2 from stationary combustion sources shall submit an emissions data report for each report year:

(1) Stationary Combustion emissions:

(A) Total CO_2 emissions (metric tonnes)

1. CO_2 emissions from biomass-derived fuels (metric tonnes)
2. Total CH_4 emissions (metric tonnes)
3. 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 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 CO_2 Emissions. The operator shall calculate emissions of CO_2 as specified below.

(1) The operator shall measure and report CO_2 emissions from stationary combustion using one of the following methods:

(A) Use of 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 95125(c), (d), or (h) to calculate CO_2 emissions; or
(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) Cogeneration. Operators of general stationary combustion facilities with cogeneration systems shall meet the requirements of Section 95112.

(d) Electricity Generating Units. Operators of general stationary combustion facilities generating units shall meet the requirements of Section 95111.

(e) Indirect Energy Usage. Operators of general stationary combustion facilities reporting in accordance with 20.11.48 NMAC shall calculate indirect electricity and thermal energy purchased or acquired and consumed as specified in Sections 95125 k-l.

(f) Calculation of N_2O and CH_4 emissions for 20.11.48 NMAC sources only [2010 and subsequent years]***.*** The operator shall calculate emissions of CH_4 emissions from stationary combustion using the methodologies provided in Section 95125(b).

95116. Data Requirements and Calculation Methods for Oil and Gas sources

(a) Greenhouse Gas Emissions Data Report. An operator in the North American Industrial Classification sector(s) (NAICS) listed in the table below shall include the following information in the GHG emissions data report for each report year from facility sources as specified:

NAICS	Descriptor	Source Type
211111	Exploration, Development and Petroleum or Gas Production	RICE, dehydrators & fugitives
211112	Natural Gas Liquid Extraction	Gas Plant
213112	Oil and Gas Support Activities	Miscellaneous equipment
221210	Natural Gas Distribution	RICE, dehydrators & fugitives
486210	Natural Gas Distribution	RICE, dehydrators & fugitives
486110	Pipeline transportation of crude oil	RICE, dehydrators & fugitives
486910	Pipeline transportation of refined petroleum products	RICE, dehydrators & fugitives

(1) Stationary combustion emissions:

(A) Total CO_2 emissions (metric tonnes) [2008 and subsequent years], and Total Methane emissions (metric tonnes) [2010 and subsequent years].

(2) Process emissions including fugitives:

(A) Total CO_2 emissions (metric tonnes) [2008 and subsequent years], and Total Methane emissions (metric tonnes) [2010 and subsequent years].

(3) 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 conusmption 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 percent by weight, and fuel type

(C) Average annual high heat value by fuel type reporting in units of MMbtu per fuel unit as specified in Section 95115(a)(3)(A).

(b) Calculation of CO_2 [2008 and subsequent years] ***and Methane Emissions*** [2010 and subsequent years]. The operator shall calculate emissions of CO_2 as specified below.

(1) The operator of an oil and gas facility *not using pipeline quality* natural gas 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 oil and gas facilities using pipeline quality gas or liquid fuel, the operator shall measure and report CO_2 emissions from stationary combustion using one of the following methods:

(A) Use of 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 95125(c), (d), or (h) to calculate CO_2 emissions; or
(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).

(3) Stationary Combustion – Methane emissions by Fuel Type [2010 and subsequent years]

(A) Methane emissions shall be calculated by selecting an appropriate method from one of the options provided by 95125(b).

(4) Process Vented including fugitives and non-routine CO_2 [2008 and subsequent years] **and Methane** [2010 and subsequent years] **emissions.** The operator shall calculate emissions from each applicable facility source type using the American Petroleum Insititue ("API") *Compendium of Greenhouse Gas Emissions Methodologies For The Oil and Gas Industry (Version February 2004)* referenced by Table 1.1 or Table 1.2. Emissions from each source type can be aggregated (e.g. combine emissions from each dehydrator and list total for this equipment type).

Table 1.1 Process Vented GHG Emissions

Source	**Pollutant(s)**	**Method(s)**
Glycol Dehydrator	CO_2 and Methane	5.1.1
Glycol Pumps	Methane	5.1.2
Acid Gas Removal	Methane	5.1.3
Sour Gas Treatment (Venting)	CO_2	5.1.4
Sour Gas Treatment (Incineration)	CO_2	5.1.4
Storage Tank (Flashing)	Methane	5.4.1
Gas Driven pneumatic devices	CO_2 and Methane	5.6.1
Gas Driven chemical injection pump	CO_2 and Methane	5.6.2
Storage Tank working/standing losses	CO_2 and Methane	Not Required

Table 1.2 Non Routine GHG Emissions

Source	**Pollutant(s)**	**Method(s)**
Emergency or Upset Event	CO_2 and Methane	5.7.1
Scheduled or Planned Maintenance	CO_2 and Methane	5.7.2
Gas Processing	CO_2 and Methane	5.7.3
Transportation	CO_2 and Methane	5.7.4
Distribution	CO_2 and Methane	5.7.5
Equipment Leaks	CO_2 and Methane	6.1.1, 6.1.2 & 6.1.3

95117. Data Requirements and Calculation Methods for Miscelleanous Sources

(a) Greenhouse Gas Emissions Data Report. An operator subject to Greenhouse Gas Emissions reporting and not subject to the requirements specified by 95110-95116 shall include the following information in the GHG emissions data report for each report year from facility sources as specified.

(1) Stationary Combustion – CO_2 [2008 and subsequent years] **and Methane** [2010 and subsequent years] **emissions by Fuel Type.** CO_2 and Methane emissions shall be calculated by selecting an appropriate method from one of the options provided by 95125(a)-(h).

(2) Fuel and Feedstock Consumption. Fuel consumption and feedstock consumption by 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**.**

(3) Process Vented and non-routine CO_2 [2008 and subsequent years], **and Methane** [2010 and subsequent years] **emissions (>1 TPY) including fugitives.** The operator shall calculate emissions from each applicable facility source using an appropriate and relevant method for CO_2 and Methane.

PART 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 95117.

(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 AQD, MMBtu per unit of mass or volume;
EF_{CO2} = Default carbon dioxide emission factor provided in Appendix A, kg CO_2 per MMBtu; and
0.001 = Factor to convert kg to metric tonnes.

(b) Method for Calculating CH_4 [2010 and subsequent years] ***and N_2O*** [2010 and subsequent years] ***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 Appendix A for methane, 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 CH_4 emissions methodology specified in Section 95125(b)(2). The operator may elect to determine CH_4 emissions using the method specified 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 CH_4 emissions and report them in metric tonnes using the following equation:

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

Where:
CH_4 O = combustion emissions from specific fuel type, metric tonnes CH_4 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 emission factor provided in Appendix A, kg CH_4 per MMBtu; and
0.0001 = 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 emissions and report them in metric tonnes using the following equation:

$$CH_4 = Fuel * HHV_D * EF * 0.001$$

Where:
CH_4 = CH_4 emissions from a specific fuel type, metric tonnes CH_4 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; and
0.001 = Factor to convert kg to metric tonnes.

(4) The operator may elect to calculate CH_4 emissions using AQD approved source specific emission factors derived from source tests conducted at least annually under the supervision of AQD. Upon approval of a source test plan by AQD, 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 AQD, 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; and
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 fuels, and LPG (ethane, propane, isobutene, n-Butane, unspecified LPG);

2. Monthly for gases with high heat value $\geq$975 and $\leq$1100 Btu per scf including natural gas, associated gas, and mixtures of low Btu gas and natural 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);

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 the same time (day and hour) of the week and/or at a time 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 12 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 D 5865-07a.

4. For waste derived fuels use ASTM D5865-07a 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); and
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 by 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 per year;
CC_n = carbon content from fuel analysis for month “n”, percent (e.g. 95% expressed as 0.95); and
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 12 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 (Re-approved 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 per year;
CC_n = carbon content from fuel analysis for month “n”, kg C per gallon fuel;
3.664 = conversion factor for carbon to carbon dioxide; and
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 that combust 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, for STP of 60°F, and 1 atmosphere);
3.664 = conversion factor for carbon to carbon dioxide; and
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 refinery fuel gas systems and flexigas combustion in the following manner:

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

Where:
CO_2 = carbon dioxide emissions, metric tonnes/year;
Fuel_A = refinery fuel from system A combusted in day n (scf);
$CC_{An\text{-}ave}$ = system A refinery fuel gas average daily carbon content for day n (kg C/kg fuel);
$MW_{RFG\text{-}A}$ = average daily molecular weight of refinery fuel gas system A 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 for STP of 60°F and 1 atmosphere);
3.664 = conversion factor – carbon to carbon dioxide; and
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 weekly fuel specific emission factor using the equation shown below.

$$EF_{CO2\text{-}A} = CC_A/HHV_{wA} * MW_A/MVC * 3.664 * 1000$$

Where:
$EF_{CO2\text{-}A}$ = weekly 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_{wA} = weekly average 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); and
1000 = conversion factor - kg/Btu to metric tonnes/MMBtu.

(A) The operator shall determine carbon content weekly 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).

(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 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 weekly fuel emission factor calculated using the equation in Section 95125(e)(3) to calculate CO_2 emissions from all combustion devices where the fuel gas from that system was combusted, using the following equation.

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

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

The operator shall determine the weekly average high heating value (HHV_{DA}) from continuous on-line instrumentation 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:

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

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); and
$CO_{2\text{-}X}$ = 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 operate continuous emissions monitoring systems (CEMS) in response to federal, or state regulations, including operating permit programs that meet the requirements of 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 operator of a facility that combusts municipal solid waste or other waste derived-fuels and operates a CEMS in response to federal or state 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 fossils fuel with a 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 or Municipal Solid Waste.

(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; and
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; and
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, and each gas sample for analyses. 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 AQD approved source specific emission factors derived from source tests conducted at least annually under the supervision of AQD. 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 CO2 emissions as specified in Section 95125(h)(2) if applicable. Upon approval of a source test plan by AQD, 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 AQD, the operator shall use the default emission factors provided in Appendix A.

(i) Method for Calculating Fugitive CH_4 Emissions from Coal Storage. [2010 and subsequent years]

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; and
CF_2 = Conversion factor equals 2,204.6, lbs/metric ton.

(j) 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).

(k) Method for Calculating Indirect Thermal Energy Usage.

The operator 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) 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; and
0.001 = Factor to convert kg to metric tones.

(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; and
0.001 = Factor to convert kg to metric tones.

(4) The operator shall report by thermal energy provider the thermal energy consumed at the facility in British thermal units (Btu).

APPENDIX A

Quantification Procedures for the Mandatory Reporting of Greenhouse Gas Emissions in Bernalillo County

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 Albuquerque Air Quality Division, as specified in 20.11.47 NMAC and 20.11.48 NMAC. Note that for reporting year 2009, only direct emissions of CO_2 and indirect emissions of GHG are required to be reported under Bernalillo County's mandatory greenhouse gas reporting regulations. Emissions factors and methods relating to other greenhouse gases are included for informational purposes only.

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
Litres	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).

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. Fuel Use to Carbon Dioxide Emissions Estimations Method

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.

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
Natural Gas (unspecified)	MMBtu	53.02	471,520	47152
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
Landfill Gas	Scf	0.025*	916,301,950	91,630,105
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
Petroleum Coke	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 procedure.

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 procedure.

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 (*continued*). Default Carbon Content, Heat Content, and Carbon Dioxide Emission Factors from Stationary Combustion by Fuel Type

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)				
Biomass-derived Fuels (Gas)	**kg C / MMBtu**	**Btu / Standard cubic foot**	**kg CO_2 / Standard cub. 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_{2f} from combustion and the pass-through CO_2, which are assume to be in equal proportions.

Source: U.S. EPA, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2005* (2007), Annex 2.1, Tables A-28, A-31, A-32, A-35, and A-36, except: Heat Content factors for Unspecified Coal (by sector), Coke, Naphtha (<401 deg. F), and Other Oil (>401 deg. F) (from U.S. Energy Information Administration, *Annual Energy Review 2005* (2006), Tables A-1, A-4, and A-5); Heat Content factors for Coal (by type) and LPG and all factors for Wood and Wood Waste, Landfill Gas, and Wastewater Treatment Biogas (from EPA Climate Leaders, Stationary Combustion Guidance (2004), Tables B-1 and B-2). MSW from Energy Information Administration, http://www.eia.doe/gov/oiaf/1605/factors.html and from California Air Resources Board, MSW California Air Resources Board, 2008

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 procedure. For readability these emission factors are provided in units of grams/MMBtu, but should be converted to kg/MMBtu (i.e. divided by a 1000) when using them in equation 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) 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 procedure.

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)

(d) 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(i) of the procedure.

Table 10. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH4 ft3 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 (ft3 per Short Ton). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.

(e) 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 procedure.

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	0.00624

Source: US EPA Title 40 CFR 63.1564

(f) Methane and Nitrous Oxide Emission Factor for Wastewater Treatment

The method to derive an emission factors 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 procedure.

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_0 = 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)
3

Emission Factor for N_2O from discharged wastewater
EF_{N2O} = 0.005 kg N_2O-N/kg-N

(g) 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 NMVOC/m^3 wastewater treated
Gravity type - uncovered	1.11e-01
Gravity type - covered	3.30e03
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

(h) 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
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