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*Unofficial electronic compilation of the
U.S. EPA Final Rule on Mandatory Reporting of Greenhouse Gases
incorporated by reference in California's Regulation for the
Mandatory Reporting of Greenhouse Gas Emissions*

Unofficial Electronic Compilation

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ARB's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions (title 17, California Code of Regulations (CCR), sections 95100-95157) incorporated by reference certain requirements promulgated by the United States Environmental Protection Agency (U.S. EPA) in its Final Rule on Mandatory Reporting of Greenhouse Gases (Title 40, Code of Federal Regulations (CFR), Part 98). Specifically, section 95100(c) of ARB's regulation incorporated those requirements promulgated by U.S. EPA as published in the Federal Register on October 30, 2009, July 12, 2010, September 22, 2010, October 28, 2010, November 30, 2010, December 17, 2010, and April 25, 2011.

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**40 CFR Parts 98
Subpart Y**

Mandatory Reporting of Greenhouse Gases

PART 98—MANDATORY GREENHOUSE GAS REPORTING

Subpart Y—Petroleum Refineries

§98.250 Definition of Source Category.

§98.251 Reporting threshold.

§98.252 GHGs to report.

§98.253 Calculating GHG emissions.

§98.254 Monitoring and QA/QC requirements.

§98.255 Procedures for estimating missing data.

§98.256 Data reporting requirements.

§98.257 Records that must be retained.

§98.258 Definitions.

§98.250 Definition of Source Category.

(a) A petroleum refinery is any facility engaged in producing gasoline, gasoline blending stocks, naphtha, kerosene, distillate fuel oils, residual fuel oils, lubricants, or asphalt (bitumen) through distillation of petroleum or through redistillation, cracking, or reforming of unfinished petroleum derivatives, except as provided in paragraph (b) of this section.

(b) For the purposes of this subpart, facilities that distill only pipeline transmix (off-spec material created when different specification products mix during pipeline transportation) are not petroleum refineries, regardless of the products produced.

(c) This source category consists of the following sources at petroleum refineries: catalytic cracking units; fluid coking units; delayed coking units; catalytic reforming units; coke calcining units; asphalt blowing operations; blowdown systems; storage tanks; process equipment components (compressors, pumps, valves, pressure relief devices, flanges, and connectors) in gas service; marine vessel, barge, tanker truck, and similar loading operations; flares; sulfur recovery plants; and non-merchant hydrogen plants (i.e., hydrogen plants that are owned or under the direct control of the refinery owner and operator).

§98.251 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a petroleum refineries process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.252 GHGs to report.

You must report:

(a) CO₂, CH₄, and N₂O combustion emissions from stationary combustion units and from each flare. Calculate and report the emissions from stationary combustion units under subpart C of this part

(General Stationary Fuel Combustion Sources) by following the requirements of subpart C, except for emissions from combustion of fuel gas, use either Equation C-5 in subpart C of this part or the Tier 4 methodology in subpart C of this part, unless either of the conditions in paragraphs (a)(1) or (2) of this section are met, in which case use either Equations C-1 or C-2a in subpart C of this part. For CH₄ and CO₂ emissions from combustion of fuel gas, use the applicable procedures in §98.33(c) for the same tier methodology that was used for calculating CO₂ emissions. (Use the default CH₄ and N₂O emission factors for "Petroleum (All fuel types in Table C-1)" in Table C-2 of this part. For Tier 3, use either the default high heat value for fuel gas in Table C-1 of subpart C of this part or a calculated HHV, as allowed in Equation C-8 of subpart C of this part.) You may aggregate units, monitor common stacks, or monitor common (fuel) pipes as provided in §98.36(c) when calculating and reporting emissions from stationary combustion units. Calculate and report the emissions from flares under this subpart.

(1) The annual average fuel gas flow rate in the fuel gas line to the combustion unit, prior to any split to individual burners or ports, does not exceed 345 standard cubic feet per minute at 60 °F and 14.7 pounds per square inch absolute and either of the conditions in paragraph (a)(1)(i) or (ii) of this section exist. Calculate the annual average flow rate using company records assuming total flow is evenly distributed over 525,600 minutes per year.

(i) A flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe.

(ii) The fuel gas line contains only vapors from loading or unloading, waste or wastewater handling, and remediation activities that are combusted in a thermal oxidizer or thermal incinerator.

(2) The combustion unit has a maximum rated heat input capacity of less than 30 mmBtu/hr and either of the following conditions exist:

(i) A flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe; or

(ii) The fuel gas line contains only vapors from loading or unloading, waste or wastewater handling, and remediation activities that are combusted in a thermal oxidizer or thermal incinerator.

(b) CO₂, CH₄, and N₂O coke burn-off emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit under this subpart.

(c) CO₂ emissions from sour gas sent off site for sulfur recovery operations under this subpart. You must follow the calculation methodologies from §98.253(f) and the monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of this subpart.

(d) CO₂ process emissions from each on-site sulfur recovery plant under this subpart.

(e) CO₂, CH₄, and N₂O emissions from each coke calcining unit under this subpart.

(f) CO₂ and CH₄ emissions from asphalt blowing operations under this subpart.

(g) CH₄ emissions from equipment leaks, storage tanks, loading operations, delayed coking units, and uncontrolled blowdown systems under this subpart.

(h) CO₂, CH₄, and N₂O emissions from each process vent not specifically included in paragraphs (a) through (g) of this section under this subpart.

(i) CO₂ emissions from non-merchant hydrogen production process units (not including hydrogen produced from catalytic reforming units) under this subpart. You must follow the calculation methodologies, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart P of this part.

§98.253 Calculating GHG emissions.

(a) Calculate GHG emissions required to be reported in §98.252(b) through (i) using the applicable methods in paragraphs (b) through (n) of this section.

(b) For flares, calculate GHG emissions according to the requirements in paragraphs (b)(1) through (b)(3) of this section.

(1) Calculate the CO₂ emissions according to the applicable requirements in paragraphs (b)(1)(i) through (b)(1)(iii) of this section.

(i) Flow measurement. If you have a continuous flow monitor on the flare, you must use the measured flow rates when the monitor is operational and the flow rate is within the calibrated range of the measurement device to calculate the flare gas flow. If you do not have a continuous flow monitor on the flare and for periods when the monitor is not operational or the flow rate is outside the calibrated range of the measurement device, you must use engineering calculations, company records, or similar estimates of volumetric flare gas flow.

(ii) Heat value or carbon content measurement. If you have a continuous higher heating value monitor or gas composition monitor on the flare or if you monitor these parameters at least weekly, you must use the measured heat value or carbon content value in calculating the CO₂ emissions from the flare using the applicable methods in paragraphs (b)(1)(ii)(A) and (b)(1)(ii)(B).

(A) If you monitor gas composition, calculate the CO₂ emissions from the flare using Equation Y-1a or Equation Y-1b of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y-1a or Equation Y-1b of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^n \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \quad (\text{Eq. Y-1a})$$

Where:

- CO₂ = Annual CO₂ emissions for a specific fuel type (metric tons/year).
- 0.98 = Assumed combustion efficiency of a flare.
- 0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
- n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
- p = Measurement period index.
- 44 = Molecular weight of CO₂ (kg/kg-mole).
- 12 = Atomic weight of C (kg/kg-mole).
- (Flare)_p = Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term “(MW)_p/MVC” with “1”.
- (MW)_p = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

- MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 pounds per square inch absolute (psia) or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
- (CC)_p = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.

$$CO_2 = \sum_{p=1}^n \left[(Flare)_p \times \frac{44}{MVC} \times 0.001 \times \left(\frac{(\%CO_2)_p}{100\%} + \sum_{x=1}^y \left\{ 0.98 \times \frac{(\%C_x)_p}{100\%} \times CMN_x \right\} \right) \right] \quad (\text{Eq. Y-1b})$$

Where:

- CO₂ = Annual CO₂ emissions for a specific fuel type (metric tons/year).
- n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
- p = Measurement period index.
- (Flare)_p = Volume of flare gas combusted during measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, you must determine the average molecular weight of the flare gas during the measurement period and convert the mass flow to a volumetric flow.
- 44 = Molecular weight of CO₂ (kg/kg-mole).
- MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
- 0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
- (%CO₂)_p = Mole percent CO₂ concentration in the flare gas stream during the measurement period (mole percent = percent by volume).
- y = Number of carbon-containing compounds other than CO₂ in the flare gas stream.
- x = Index for carbon-containing compounds other than CO₂.
- 0.98 = Assumed combustion efficiency of a flare (mole CO₂ per mole carbon).
- (%C_x)_p = Mole percent concentration of compound "x" in the flare gas stream during the measurement period (mole percent = percent by volume)
- CMN_x = Carbon mole number of compound "x" in the flare gas stream (mole carbon atoms per mole compound). E.g., CMN for ethane (C₂H₆) is 2; CMN for propane (C₃H₈) is 3.

CO₂

(B) If you monitor heat content but do not monitor gas composition, calculate the CO₂ emissions from the flare using Equation Y-2 of this section. If daily or more frequent measurement data are available, you must use daily values when using Equation Y-2 of this section; otherwise, use weekly values.

$$CO_2 = 0.98 \times 0.001 \times \sum_{p=1}^n \left[(Flare)_p \times (HHV)_p \times EmF \right] \quad (\text{Eq. Y-2})$$

Where:

- CO₂ = Annual CO₂ emissions for a specific fuel type (metric tons/year).
- 0.98 = Assumed combustion efficiency of a flare.
- 0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
- n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
- p = Measurement period index.
- (Flare)_p = Volume of flare gas combusted during measurement period (million (MM) scf/period). If a mass flow meter is used, you must also measure molecular weight and convert the mass flow to a volumetric flow as follows: $Flare[MMscf] = 0.000001 \times Flare[kg] \times MVC/(MW)_p$, where MVC is the molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia depending on the standard conditions used when determining (HHV)_p) and (MW)_p is the average molecular weight of the flare gas combusted during measurement period (kg/kg-mole).
- (HHV)_p = Higher heating value for the flare gas combusted during measurement period (British thermal units per scf, Btu/scf = MMBtu/MMscf). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
- EmF = Default CO₂ emission factor of 60 kilograms CO₂/MMBtu (HHV basis).

(iii) Alternative to heat value or carbon content measurements. If you do not measure the higher heating value or carbon content of the flare gas at least weekly, determine the quantity of gas discharged to the flare separately for periods of routine flare operation and for periods of start-up, shutdown, or malfunction, and calculate the CO₂ emissions as specified in paragraphs (b)(1)(iii)(A) through (b)(1)(iii)(C) of this section.

(A) For periods of start-up, shutdown, or malfunction, use engineering calculations and process knowledge to estimate the carbon content of the flared gas for each start-up, shutdown, or malfunction event exceeding 500,000 scf/day.

(B) For periods of normal operation, use the average heating value measured for the fuel gas for the heating value of the flare gas. If heating value is not measured, the heating value may be estimated from historic data or engineering calculations.

(C) Calculate the CO₂ emissions using Equation Y-3 of this section.

$$CO_2 = 0.98 \times 0.001 \times \left(Flare_{Norm} \times HHV \times EmF + \sum_{p=1}^n \left[\frac{44}{12} \times (Flare_{SSM})_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) \text{ (Eq.Y-3)}$$

Where:

- CO₂ = Annual CO₂ emissions for a specific fuel type (metric tons/year).
- 0.98 = Assumed combustion efficiency of a flare.

- 0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
- Flare_{Norm} = Annual volume of flare gas combusted during normal operations from company records, (million (MM) standard cubic feet per year, MMscf/year).
- HHV = Higher heating value for fuel gas or flare gas from company records (British thermal units per scf, Btu/scf = MMBtu/MMscf).
- EmF = Default CO₂ emission factor for flare gas of 60 kilograms CO₂/MMBtu (HHV basis).
- n = Number of start-up, shutdown, and malfunction events during the reporting year exceeding 500,000 scf/day.
- p = Start-up, shutdown, and malfunction event index.
- 44 = Molecular weight of CO₂ (kg/kg-mole).
- 12 = Atomic weight of C (kg/kg-mole).
- (Flare_{SSM})_p = Volume of flare gas combusted during indexed start-up, shutdown, or malfunction event from engineering calculations, (scf/event).
- (MW)_p = Average molecular weight of the flare gas, from the analysis results or engineering calculations for the event (kg/kg-mole).
- MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
- (CC)_p = Average carbon content of the flare gas, from analysis results or engineering calculations for the event (kg C per kg flare gas).

(2) Calculate CH₄ using Equation Y-4 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH_4}}{EmF} \right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH_4} \quad (\text{Eq. Y-4})$$

Where:

- CH₄ = Annual methane emissions from flared gas (metric tons CH₄/year).
- CO₂ = Emission rate of CO₂ from flared gas calculated in paragraph (b)(1) of this section (metric tons/year).
- EmF_{CH₄} = Default CH₄ emission factor for “Petroleum Products” from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH₄/MMBtu).
- EmF = Default CO₂ emission factor for flare gas of 60 kg CO₂/MMBtu (HHV basis).
- 0.02/0.98 = correction factor for flare combustion efficiency.
- 16/44 = correction factor ratio of the molecular weight of CH₄ to CO₂
- f_{CH₄} = Weight fraction of carbon in the flare gas prior to combustion that is contributed by methane from measurement values or engineering calculations (kg C in methane in flare gas/kg C in flare gas); default is 0.4.

(3) Calculate N₂O emissions using Equation Y-5 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_{N_2O}}{EmF} \right) \quad (\text{Eq. Y-5})$$

Where:

- N_2O = Annual nitrous oxide emissions from flared gas (metric tons N_2O /year).
- CO_2 = Emission rate of CO_2 from flared gas calculated in paragraph (b)(1) of this section (metric tons/year).
- EmF_{N_2O} = Default N_2O emission factor for “Petroleum Products” from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources)(kg N_2O /MMBtu).
- EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2 /MMBtu (HHV basis).

(c) For catalytic cracking units and traditional fluid coking units, calculate the GHG emissions using the applicable methods described in paragraphs (c)(1) through (c)(5) of this section.

(1) If you operate and maintain a CEMS that measures CO_2 emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate and report CO_2 emissions as provided in paragraphs (c)(1)(i) and (c)(1)(ii) of this section. Other catalytic cracking units and traditional fluid coking units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Combustion Sources), or follow the requirements of paragraphs (c)(2) or (3) of this section.

(i) Calculate CO_2 emissions by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(ii) For catalytic cracking units whose process emissions are discharged through a combined stack with other CO_2 emissions (e.g., co-mingled with emissions from a CO boiler), you must also calculate the other CO_2 emissions using the applicable methods for the applicable subparts (e.g., subpart C of this part in the case of a CO boiler). Calculate the process emissions from the catalytic cracking unit or fluid coking unit as the difference in the CO_2 CEMS emissions and the calculated emissions associated with the additional units discharging through the combined stack.

(2) For catalytic cracking units and fluid coking units with rated capacities greater than 10,000 barrels per stream day (bbls/sd) that do not use a continuous CO_2 CEMS for the final exhaust stack, you must continuously or no less frequently than hourly monitor the O_2 , CO_2 , and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels and calculate the CO_2 emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section:

(i) Calculate the CO_2 emissions from each catalytic cracking unit and fluid coking unit using Equation Y-6 of this section.

$$CO_2 = \sum_{p=1}^n \left[(Q_r)_p \times \frac{(\%CO_2 + \%CO)_p}{100\%} \times \frac{44}{MVC} \times 0.001 \right] \quad (\text{Eq. Y-6})$$

Where:

- CO₂ = Annual CO₂ mass emissions (metric tons/year).
- Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dry standard cubic feet per hour, dscfh).
- %CO₂ = Hourly average percent CO₂ concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis).
- %CO = Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis). When there is no post-combustion device, assume %CO to be zero.
- 44 = Molecular weight of CO₂ (kg/kg-mole).
- MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
- 0.001 = Conversion factor (metric ton/kg).
- n = Number of hours in calendar year.

(ii) Either continuously monitor the volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels or calculate the volumetric flow rate of this exhaust gas stream using Equation Y-7a or Equation Y-7b of this section.

$$Q_r = \frac{(79 * Q_a + (100 - \%O_{oxy}) * Q_{oxy})}{100 - \%CO_2 - \%CO - \%O_2} \quad (\text{Eq. Y-7a})$$

Where:

- Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dscfh).
- Q_a = Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).
- Q_{oxy} = Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner as determined from control room instrumentation (dscfh).
- %O₂ = Hourly average percent oxygen concentration in exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis).
- %O_{oxy} = O₂ concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on oxygen purity specifications of the oxygen supply used for enrichment (percent by volume – dry basis).
- %CO₂ = Hourly average percent CO₂ concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis).
- %CO = Hourly average percent CO concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume – dry basis). When no auxiliary fuel is burned and a continuous CO monitor is not required under 40 CFR part 63 subpart UUU, assume %CO to be zero.

$$Q_r = \frac{(78.1 * Q_a + (\%N_{2,oxy}) * Q_{oxy})}{\%N_{2,exhaust}} \quad (\text{Eq. Y-7b})$$

Where:

- Q_r = Volumetric flow rate of exhaust gas from the fluid catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels (dscfh).
- Q_a = Volumetric flow rate of air to the fluid catalytic cracking unit regenerator or fluid coking unit burner, as determined from control room instrumentation (dscfh).
- Q_{oxy} = Volumetric flow rate of oxygen enriched air to the fluid catalytic cracking unit regenerator or fluid coking unit burner as determined from control room instrumentation (dscfh).
- $\%N_{2,oxy}$ = N₂ concentration in oxygen enriched gas stream inlet to the fluid catalytic cracking unit regenerator or fluid coking unit burner based on measured value or maximum N₂ impurity specifications of the oxygen supply used for enrichment (percent by volume—dry basis).
- $\%N_{2,exhaust}$ = Hourly average percent N₂ concentration in the exhaust gas stream from the fluid catalytic cracking unit regenerator or fluid coking unit burner (percent by volume—dry basis).

(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must determine the CO₂ emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C and report those emissions by following the requirements of subpart C of this part.

(3) For catalytic cracking units and fluid coking units with rated capacities of 10,000 barrels per stream day (bbls/sd) or less that do not use a continuous CO₂ CEMS for the final exhaust stack, comply with the requirements in paragraphs (c)(3)(i) of this section or paragraphs (c)(3)(ii) and (c)(3)(iii) of this section, as applicable.

(i) If you continuously or no less frequently than daily monitor the O₂, CO₂, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels, you must calculate the CO₂ emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section, except that daily averages are allowed and the summation can be performed on a daily basis.

(ii) If you do not monitor at least daily the O₂, CO₂, and (if necessary) CO concentrations in the exhaust stack from the catalytic cracking unit regenerator or fluid coking unit burner prior to the combustion of other fossil fuels, calculate the CO₂ emissions from each catalytic cracking unit and fluid coking unit using Equation Y-8 of this section.

$$CO_2 = Q_{unit} \times (CBF \times 0.001) \times CC \times \frac{44}{12} \quad (\text{Eq. Y-8})$$

Where:

- CO₂ = Annual CO₂ mass emissions (metric tons/year).

Q_{unit}	=	Annual throughput of unit from company records (barrels (bbls) per year, bbl/yr).
CBF	=	Coke burn-off factor from engineering calculations (kg coke per barrel of feed); default for catalytic cracking units = 7.3; default for fluid coking units = 11.
0.001	=	Conversion factor (metric ton/kg).
CC	=	Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.
44/12	=	Ratio of molecular weight of CO ₂ to C (kg CO ₂ per kg C).

(iii) If you have a CO boiler that uses auxiliary fuels or combusts materials other than catalytic cracking unit or fluid coking unit exhaust gas, you must determine the CO₂ emissions resulting from the combustion of these fuels or other materials following the requirements in subpart C of this part (General Stationary Fuel Combustion Sources) and report those emissions by following the requirements of subpart C of this part.

(4) Calculate CH₄ emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y-9 of this section.

$$\text{CH}_4 = \left(\text{CO}_2 * \frac{\text{EmF}_2}{\text{EmF}_1} \right) \quad (\text{Eq. Y-9})$$

Where:

CH ₄	=	Annual methane emissions from coke burn-off (metric tons CH ₄ /year).
CO ₂	=	Emission rate of CO ₂ from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), (e)(2), (g)(1), or (g)(2) of this section, as applicable (metric tons/year).
EmF ₁	=	Default CO ₂ emission factor for petroleum coke from Table C-1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO ₂ /MMBtu).
EmF ₂	=	Default CH ₄ emission factor for "Petroleum Products" from Table C-2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH ₄ /MMBtu).

(5) Calculate N₂O emissions using either unit specific measurement data, a unit-specific emission factor based on a source test of the unit, or Equation Y-10 of this section.

$$\text{N}_2\text{O} = \left(\text{CO}_2 * \frac{\text{EmF}_3}{\text{EmF}_1} \right) \quad (\text{Eq. Y-10})$$

Where:

N ₂ O	=	Annual nitrous oxide emissions from coke burn-off (mt N ₂ O/year).
CO ₂	=	Emission rate of CO ₂ from coke burn-off calculated in paragraphs (c)(1), (c)(2), (e)(1), (e)(2), (g)(1), or (g)(2) of this section, as applicable (metric tons/year).
EmF ₁	=	Default CO ₂ emission factor for petroleum coke from Table C-1 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CO ₂ /MMBtu).

EmF₃ = Default N₂O emission factor for "Petroleum Products" from Table C-2 of subpart C of this part (kg N₂O/MMBtu).

(d) For fluid coking units that use the flexicoking design, the GHG emissions from the resulting use of the low value fuel gas must be accounted for only once. Typically, these emissions will be accounted for using the methods described in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may use the methods in paragraph (c) of this section provided that you do not otherwise account for the subsequent combustion of this low value fuel gas.

(e) For catalytic reforming units, calculate the CO₂ emissions using the applicable methods described in paragraphs (e)(1) through (e)(3) of this section and calculate the CH₄ and N₂O emissions using the methods described in paragraphs (c)(4) and (c)(5) of this section, respectively.

(1) If you operate and maintain a CEMS that measures CO₂ emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate CO₂ emissions as provided in paragraphs (c)(1)(i) and (c)(1)(ii) of this section. Other catalytic reforming units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (e)(2) or (e)(3) of this section.

(2) If you continuously or no less frequently than daily monitor the O₂, CO₂, and (if necessary) CO concentrations in the exhaust stack from the catalytic reforming unit catalyst regenerator prior to the combustion of other fossil fuels, you must calculate the CO₂ emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section.

(3) Calculate CO₂ emissions from the catalytic reforming unit catalyst regenerator using Equation Y-11 of this section.

$$CO_2 = \sum_1^n \left[(CB_Q)_n \times CC \times \frac{44}{12} \times 0.001 \right] \quad (\text{Eq. Y-11})$$

Where:

CO₂ = Annual CO₂ emissions (metric tons/year).

CB_Q = Coke burn-off quantity per regeneration cycle or measurement period from engineering estimates (kg coke/cycle or kg coke/measurement period).

n = Number of regeneration cycles or measurement periods in the calendar year.

CC = Carbon content of coke based on measurement or engineering estimate (kg C per kg coke); default = 0.94.

44/12 = Ratio of molecular weight of CO₂ to C (kg CO₂ per kg C).

0.001 = Conversion factor (metric ton/kg).

(f) For on-site sulfur recovery plants and for sour gas sent off site for sulfur recovery, calculate and report CO₂ process emissions from sulfur recovery plants according to the requirements in paragraphs (f)(1) through (f)(5) of this section, or, for non-Claus sulfur recovery plants, according to the requirements in paragraph (j) of this section regardless of the concentration of CO₂ in the vented gas stream. Combustion emissions from the sulfur recovery plant (e.g., from fuel combustion in the Claus burner or the tail gas treatment incinerator) must be reported under subpart C of this part (General

Stationary Fuel Combustion Sources). For the purposes of this subpart, the sour gas stream for which monitoring is required according to paragraphs (f)(2) through (f)(5) of this section is not considered a fuel.

(1) If you operate and maintain a CEMS that measures CO₂ emissions according to subpart C of this part, you must calculate CO₂ emissions under this subpart by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor fuel use in the Claus burner, tail gas incinerator, or other combustion sources that discharge via the final exhaust stack from the sulfur recovery plant and calculate the combustion emissions from the fuel use according to subpart C of this part. Calculate the process emissions from the sulfur recovery plant as the difference in the CO₂ CEMS emissions and the calculated combustion emissions associated with the sulfur recovery plant final exhaust stack. Other sulfur recovery plants must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C, or follow the requirements of paragraphs (f)(2) through (f)(5) of this section, or (for non-Claus sulfur recovery plants only) follow the requirements in paragraph (j) of this section to determine CO₂ emissions for the sulfur recovery plant.

(2) Flow measurement. If you have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use the measured flow rates when the monitor is operational to calculate the sour gas flow rate. If you do not have a continuous flow monitor on the sour gas feed to the sulfur recovery plant, you must use engineering calculations, company records, or similar estimates of volumetric sour gas flow.

(3) Carbon content. If you have a continuous gas composition monitor capable of measuring carbon content on the sour gas feed to the sulfur recovery plant or if you monitor gas composition for carbon content on a routine basis, you must use the measured carbon content value. Alternatively, you may develop a site-specific carbon content factor using limited measurement data or engineering estimates or use the default factor of 0.20.

(4) Calculate the CO₂ emissions from each sulfur recovery plant using Equation Y-12 of this section.

$$CO_2 = F_{SG} * \frac{44}{MVC} * MF_C * 0.001 \quad (\text{Eq. Y-12})$$

Where:

CO₂ = Annual CO₂ emissions (metric tons/year).

F_{SG} = Volumetric flow rate of sour gas feed (including sour water stripper gas) to the sulfur recovery plant (scf/year).

44 = Molecular weight of CO₂ (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).

MF_C = Mole fraction of carbon in the sour gas to the sulfur recovery plant (kg-mole C/kg-mole gas); default = 0.20.

0.001 = Conversion factor, kg to metric tons

(5) If tail gas is recycled to the front of the sulfur recovery plant and the recycled flow rate and carbon content is included in the measured data under paragraphs (f)(2) and (f)(3) of this section, respectively, then the annual CO₂ emissions calculated in paragraph (f)(4) of this section must be corrected to avoid double counting these emissions. You may use engineering estimates to perform this correction or assume that the corrected CO₂ emissions are 95 percent of the uncorrected value calculated using Equation Y-12 of this section.

(g) For coke calcining units, calculate GHG emissions according to the applicable provisions in paragraphs (g)(1) through (g)(3) of this section.

(1) If you operate and maintain a CEMS that measures CO₂ emissions according to subpart C of this part, you must calculate and report CO₂ emissions under this subpart by following the Tier 4 Calculation Methodology specified in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). You must monitor fuel use in the coke calcining unit that discharges via the final exhaust stack from the coke calcining unit and calculate the combustion emissions from the fuel use according to subpart C of this part. Calculate the process emissions from the coke calcining unit as the difference in the CO₂ CEMS emissions and the calculated combustion emissions associated with the coke calcining unit final exhaust stack. Other coke calcining units must either install a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part, or follow the requirements of paragraph (g)(2) of this section.

(2) Calculate the CO₂ emissions from the coke calcining unit using Equation Y-13 of this section.

$$CO_2 = \frac{44}{12} * (M_{in} * CC_{GC} - (M_{out} + M_{dust}) * CC_{MPC}) \quad (\text{Eq. Y-13})$$

Where:

CO₂ = Annual CO₂ emissions (metric tons/year).

M_{in} = Annual mass of green coke fed to the coke calcining unit from facility records (metric tons/year).

CC_{GC} = Average mass fraction carbon content of green coke from facility measurement data (metric ton carbon/metric ton green coke).

M_{out} = Annual mass of marketable petroleum coke produced by the coke calcining unit from facility records (metric tons petroleum coke/year).

M_{dust} = Annual mass of petroleum coke dust removed from the process through the dust collection system of the coke calcining unit from facility records (metric ton petroleum coke dust/year). For coke calcining units that recycle the collected dust, the mass of coke dust removed from the process is the mass of coke dust collected less the mass of coke dust recycled to the process.

CC_{MPC} = Average mass fraction carbon content of marketable petroleum coke produced by the coke calcining unit from facility measurement data (metric ton carbon/metric ton petroleum coke).

44 = Molecular weight of CO₂ (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

(3) For all coke calcining units, use the CO₂ emissions from the coke calcining unit calculated in paragraphs (g)(1) or (g)(2), as applicable, and calculate CH₄ using the methods described in paragraph (c)(4) of this section and N₂O emissions using the methods described in paragraph (c)(5) of this section.

(h) For asphalt blowing operations, calculate CO₂ and CH₄ emissions according to the requirements in paragraph (j) of this section regardless of the CO₂ and CH₄ concentrations or according to the applicable provisions in paragraphs (h)(1) and (h)(2) of this section.

(1) For uncontrolled asphalt blowing operations or asphalt blowing operations controlled by vapor scrubbing, calculate CO₂ and CH₄ emissions using Equations Y-14 and Y-15 of this section, respectively.

$$CO_2 = (Q_{AB} \times EF_{AB,CO_2}) \quad (\text{Eq. Y-14})$$

Where:

CO₂ = Annual CO₂ emissions from uncontrolled asphalt blowing (metric tons CO₂/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

EF_{AB,CO₂} = Emission factor for CO₂ from uncontrolled asphalt blowing from facility-specific test data (metric tons CO₂/MMbbl asphalt blown); default = 1,100.

$$CH_4 = (Q_{AB} \times EF_{AB,CH_4}) \quad (\text{Eq. Y-15})$$

Where:

CH₄ = Annual methane emissions from uncontrolled asphalt blowing (metric tons CH₄/year).

Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).

EF_{AB,CH₄} = Emission factor for CH₄ from uncontrolled asphalt blowing from facility-specific test data (metric tons CH₄/MMbbl asphalt blown); default = 580.

(2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate CO₂ using either Equations Y-16a or Y-16b of this section and calculate CH₄ emissions using Equation Y-17 of this section, provided these emissions are not already included in the flare emissions calculated in paragraph (b) of this section or in the stationary combustion unit emissions required under subpart C of this part (General Stationary Fuel Combustion Sources).

$$CO_2 = 0.98 \times \left(Q_{AB} \times CEF_{AB} \times \frac{44}{12} \right) \quad (\text{Eq. Y-16a})$$

Where:

CO₂ = Annual CO₂ emissions from controlled asphalt blowing (metric tons CO₂/year).

0.98 = Assumed combustion efficiency of thermal oxidizer or flare.

Q_{AB} = Quantity of asphalt blown (MMbbl/year).

CEF_{AB} = Carbon emission factor from asphalt blowing from facility-specific test data (metric tons C/MMbbl asphalt blown); default = 2,750.

44 = Molecular weight of CO₂ (kg/kg-mole).

12 = Atomic weight of C (kg/kg-mole).

$$CO_2 = Q_{AB} \times \left(EF_{AB,CO_2} + 0.98 \times \left[\left(CEF_{AB} \times \frac{44}{12} \right) - EF_{AB,CO_2} \right] \right) \quad (\text{Eq. Y-16b})$$

Where:

- CO₂ = Annual CO₂ emissions from controlled asphalt blowing (metric tons CO₂/year).
- Q_{AB} = Quantity of asphalt blown (MMbbl/ year).
- 0.98 = Assumed combustion efficiency of thermal oxidizer or flare.
- EF_{AB,CO₂} = Emission factor for CO₂ from uncontrolled asphalt blowing from facility-specific test data (metric tons CO₂/MMbbl asphalt blown); default =1,100.
- CEF_{AB} = Carbon emission factor from asphalt blowing from facility-specific test data (metric tons C/MMbbl asphalt blown); default = 2,750.
- 44 = Molecular weight of CO₂ (kg/kg-mole).
- 12 = Atomic weight of C (kg/kg-mole).

$$CH_4 = 0.02 \times (Q_{AB} \times EF_{AB,CH_4}) \quad (\text{Eq. Y-17})$$

Where:

- CH₄ = Annual methane emissions from controlled asphalt blowing (metric tons CH₄/year).
- 0.02 = Fraction of methane uncombusted in thermal oxidizer or flare based on assumed 98% combustion efficiency.
- Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).
- EF_{AB,CH₄} = Emission factor for CH₄ from uncontrolled asphalt blowing from facility-specific test data (metric tons CH₄/MMbbl asphalt blown); default = 580.

(i) For delayed coking units, calculate the CH₄ emissions from the depressurization of the coking unit vessel (i.e., the "coke drum") to atmosphere using either of the methods provided in paragraphs (i)(1) or (i)(2), provided no water or steam is added to the vessel once it is vented to the atmosphere. You must use the method in paragraph (i)(1) of this section if you add water or steam to the vessel after it is vented to the atmosphere.

(1) Use the process vent method in paragraph (j) of this section to calculate the CH₄ emissions from the depressurization of the coke drum or vessel regardless of the CH₄ concentration and also calculate the CH₄ emissions from the subsequent opening of the vessel for coke cutting operations using Equation Y-18 of this section. If you have coke drums or vessels of different dimensions, use the process vent method in paragraph (j) of this section and Equation Y-18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH₄ emissions for all delayed coking units.

$$CH_4 = \left(N \times H \times \frac{(P_{CV} + 14.7)}{14.7} \times f_{void} \times \frac{\pi \times D^2}{4} \times \frac{16}{MVC} \times MF_{CH_4} \times 0.001 \right) \quad (\text{Eq. Y-18})$$

Where:

CH ₄	=	Annual methane emissions from the delayed coking unit vessel opening (metric ton/year).
N	=	Cumulative number of vessel openings for all delayed coking unit vessels of the same dimensions during the year.
H	=	Height of coking unit vessel (feet).
P _{CV}	=	Gauge pressure of the coking vessel when opened to the atmosphere prior to coke cutting or, if the alternative method provided in paragraph (i)(2) of this section is used, gauge pressure of the coking vessel when depressurization gases are first routed to the atmosphere (pounds per square inch gauge, psig)
14.7	=	Assumed atmospheric pressure (pounds per square inch, psi)
f _{Void}	=	Volumetric void fraction of coking vessel prior to steaming (cf gas/cf of vessel); default = 0.6.
D	=	Diameter of coking unit vessel (feet).
16	=	Molecular weight of CH ₄ (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
MFCH ₄	=	Mole fraction of methane in coking vessel gas (kg-mole CH ₄ /kg-mole gas, wet basis); default value is 0.01.
0.001	=	Conversion factor (metric ton/kg).

(2) Calculate the CH₄ emissions from the depressurization vent and subsequent opening of the vessel for coke cutting operations using Equation Y-18 of this section and the pressure of the coking vessel when the depressurization gases are first routed to the atmosphere. If you have coke drums or vessels of different dimensions, use Equation Y-18 for each set of coke drums or vessels of the same size and sum the resultant emissions across each set of coke drums or vessels to calculate the CH₄ emissions for all delayed coking units.

(j) For each process vent not covered in paragraphs (a) through (i) of this section that can be reasonably expected to contain greater than 2 percent by volume CO₂ or greater than 0.5 percent by volume of CH₄ or greater than 0.01 percent by volume (100 parts per million) of N₂O, calculate GHG emissions using the Equation Y-19 of this section. You must use Equation Y-19 of this section to calculate CH₄ emissions for catalytic reforming unit depressurization and purge vents when methane is used as the purge gas or if you elected this method as an alternative to the methods in paragraphs (f), (h), or (k) of this section.

$$E_x = \sum_{p=1}^N \left((VR)_p \times (MF_x)_p \times \frac{MW_x}{MVC} \times (VT)_p \times 0.001 \right) \quad (\text{Eq. Y-19})$$

Where:

E _x	=	Annual emissions of each GHG from process vent (metric ton/yr).
N	=	Number of venting events per year.
P	=	Index of venting events.

$(VR)_p$	=	Average volumetric flow rate of process gas during the event (scf per hour) from measurement data, process knowledge, or engineering estimates.
$(MF_x)_p$	=	Mole fraction of GHG x in process vent during the event (kg-mol of GHG x/kg-mol vent gas) from measurement data, process knowledge, or engineering estimates.
MW_x	=	Molecular weight of GHG x (kg/kg-mole); use 44 for CO ₂ or N ₂ O and 16 for CH ₄ .
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
$(VT)_p$	=	Venting time for the event, (hours).
0.001	=	Conversion factor (metric ton/kg)

(k) For uncontrolled blowdown systems, you must calculate CH₄ emissions either using the methods for process vents in paragraph (j) of this section regardless of the CH₄ concentration or using Equation Y20 of this section. Blowdown systems where the uncondensed gas stream is routed to a flare or similar control device is considered to be controlled and is not required to estimate emissions under this paragraph (k).

$$CH_4 = \left(Q_{Ref} \times EF_{BD} \times \frac{16}{MVC} \times 0.001 \right) \quad (\text{Eq. Y-20})$$

Where:

CH ₄	=	Methane emission rate from blowdown systems (mt CH ₄ /year).
Q _{Ref}	=	Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).
EF _{BD}	=	Methane emission factor for uncontrolled blown systems (scf CH ₄ /MMbbl); default is 137,000.
16	=	Molecular weight of CH ₄ (kg/kg-mole).
MVC	=	Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
0.001	=	Conversion factor (metric ton/kg).

(l) For equipment leaks, calculate CH₄ emissions using the method specified in either paragraph (l)(1) or (l)(2) of this section.

(1) Use process-specific methane composition data (from measurement data or process knowledge) and any of the emission estimation procedures provided in the Protocol for Equipment Leak Emissions Estimates (EPA-453/R-95-017, NTIS PB96-175401).

(2) Use Equation Y-21 of this section.

$$CH_4 = (0.4 \times N_{CD} + 0.2 \times N_{PU1} + 0.1 \times N_{PU2} + 4.3 \times N_{H2} + 6 \times N_{FGS}) \quad (\text{Eq. Y-21})$$

Where:

CH ₄	=	Annual methane emissions from equipment leaks (metric tons/year)
N _{CD}	=	Number of atmospheric crude oil distillation columns at the facility.

- N_{PU1} = Cumulative number of catalytic cracking units, coking units (delayed or fluid), hydrocracking, and full-range distillation columns (including depropanizer and debutanizer distillation columns) at the facility.
- N_{PU2} = Cumulative number of hydrotreating/hydrorefining units, catalytic reforming units, and visbreaking units at the facility.
- N_{H2} = Total number of hydrogen plants at the facility.
- N_{FGS} = Total number of fuel gas systems at the facility.

(m) For storage tanks, except as provided in paragraph (m)(4) of this section, calculate CH_4 emissions using the applicable methods in paragraphs (m)(1) through (m)(3) of this section.

(1) For storage tanks other than those processing unstabilized crude oil, you must either calculate CH_4 emissions from storage tanks that have a vapor-phase methane concentration of 0.5 volume percent or more using tank-specific methane composition data (from measurement data or product knowledge) and the emission estimation methods provided in AP-42, Section 7.1 (incorporated by reference, see §98.7) or estimate CH_4 emissions from storage tanks using Equation Y-22 of this section.

$$CH_4 = (0.1 \times Q_{Ref}) \quad (\text{Eq. Y-22})$$

Where:

- CH_4 = Annual methane emissions from storage tanks (metric tons/year).
- 0.1 = Default emission factor for storage tanks (metric ton CH_4 /MMbbl).
- Q_{Ref} = Quantity of crude oil plus the quantity of intermediate products received from off site that are processed at the facility (MMbbl/year).

(2) For storage tanks that process unstabilized crude oil, calculate CH_4 emissions from the storage of unstabilized crude oil using either tank-specific methane composition data (from measurement data or product knowledge) and direct measurement of the gas generation rate or by using Equation Y-23 of this section.

$$CH_4 = (995,000 \times Q_{un} \times \Delta P) \times MF_{CH_4} \times \frac{16}{MVC} \times 0.001 \quad (\text{Eq. Y-23})$$

Where:

- CH_4 = Annual methane emissions from storage tanks (metric tons/year).
- Q_{un} = Quantity of unstabilized crude oil received at the facility (MMbbl/year).
- ΔP = Pressure differential from the previous storage pressure to atmospheric pressure (pounds per square inch, psi).
- MF_{CH_4} = Average Mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tank from facility measurements (kg-mole CH_4 /kg-mole gas); use 0.27 as a default if measurement data are not available.
- 995,000 = Correlation Equation factor (scf gas per MMbbl per psi)
- 16 = Molecular weight of CH_4 (kg/kg-mole).

- MVC = Molar volume conversion factor (849.5 scf/kg-mole at 68 °F and 14.7 psia or 836.6 scf/kg-mole at 60 °F and 14.7 psia).
- 0.001 = Conversion factor (metric ton/kg).

(3) You do not need to calculate CH₄ emissions from storage tanks that meet any of the following descriptions:

- (i) Units permanently attached to conveyances such as trucks, trailers, rail cars, barges, or ships;
- (ii) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere;
- (iii) Bottoms receivers or sumps;
- (iv) Vessels storing wastewater; or
- (v) Reactor vessels associated with a manufacturing process unit.

(n) For crude oil, intermediate, or product loading operations for which the vapor-phase concentration of methane is 0.5 volume percent or more, calculate CH₄ emissions from loading operations using vapor-phase methane composition data (from measurement data or process knowledge) and the emission estimation procedures provided in AP-42, Section 5.2 (incorporated by reference, see §98.7). For loading operations in which the equilibrium vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.

§98.254 Monitoring and QA/QC requirements.

(a) Fuel flow meters, gas composition monitors, and heating value monitors that are associated with sources that use a CEMS to measure CO₂ emissions according to subpart C of this part or that are associated with stationary combustion sources must follow the monitoring and QA/QC requirements in §98.34.

(b) All flow meters, gas composition monitors, and heating value monitors that are used to provide data for the GHG emissions calculations in this subpart for sources other than those subject to the requirements in paragraph (a) of this section shall be calibrated according to the procedures specified by the manufacturer, or according to the procedures in the applicable methods specified in paragraphs (c) through (g) of this section. In the case of gas flow meters, all gas flow meters must meet the calibration accuracy requirements in §§98.3(i). All gas flow meters, gas composition monitors, and heating value monitors must be recalibrated at the applicable frequency specified in paragraph (b)(1) or (b)(2) of this section.

(1) You must recalibrate each gas flow meter according to one of the following frequencies. You may recalibrate at the minimum frequency specified by the manufacturer, biennially (every two years), or at the interval specified by the industry consensus standard practice used.

(2) You must recalibrate each gas composition monitor and heating value monitor according to one of the following frequencies. You may recalibrate at the minimum frequency specified by the manufacturer, annually, or at the interval specified by the industry standard practice used.

(c) For flare or sour gas flow meters and gas flow meters used to comply with the requirements in §98.253(j), operate, calibrate, and maintain the flow meter according to one of the following. You may use the procedures specified by the flow meter manufacturer, or a method published by a consensus-based standards organization. Consensus-based standards organizations include, but are not limited to,

the following: ASTM International (100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428– B2959, (800) 262–1373, <http://www.astm.org>), the American National Standards Institute (ANSI, 1819 L Street, NW., 6th floor, Washington, DC 20036, (202) 293–8020, <http://www.ansi.org>), the American Gas Association (AGA, 400 North Capitol Street, NW., 4th Floor, Washington, DC 20001, (202) 824–7000, <http://www.aga.org>), the American Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, <http://www.asme.org>), the American Petroleum Institute (API, 1220 L Street, NW., Washington, DC 20005–4070, (202) 682–8000, <http://www.api.org>), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356–0060, <http://www.api.org>).

(d) Except as provided in paragraph (g) of this section, determine gas composition and, if required, average molecular weight of the gas using any of the following methods. Alternatively, the results of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph are documented in the written Monitoring Plan for the unit under §98.3(g)(5).

- (1) Method 18 at 40 CFR part 60, appendix A-6.
- (2) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, see §98.7).
- (3) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, see §98.7).
- (4) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, see §98.7).
- (5) UOP539-97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see §98.7).
- (6) ASTM D2503–92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure (incorporated by reference, see §98.7).

(e) Determine flare gas higher heating value using any of the following methods. Alternatively, the results of chromatographic analysis of the fuel may be used, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the gas chromatograph are documented in the written Monitoring Plan for the unit under §98.3(g)(5).

- (1) ASTM D4809-06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method) (incorporated by reference, see §98.7).
- (2) ASTM D240-02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (incorporated by reference, see §98.7).
- (3) ASTM D1826-94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter (incorporated by reference, see §98.7).
- (4) ASTM D3588-98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels (incorporated by reference, see §98.7).
- (5) ASTM D4891-89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion (incorporated by reference, see §98.7).

(f) For gas flow meters used to comply with the requirements in §98.253(c)(2)(ii), install, operate, calibrate, and maintain each gas flow meter according to the requirements in 40 CFR 63.1572(c) or according to the following requirements.

- (1) Locate the flow monitor at a site that provides representative flow rates. Avoid locations where there is swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.
- (2) [Reserved]
- (3) Use a continuous monitoring system capable of correcting for the temperature, pressure, and moisture content to output flow in dry standard cubic feet (standard conditions as defined in §98.6).

(g) For exhaust gas CO₂/CO/O₂ composition monitors used to comply with the requirements in §98.253(c)(2), install, operate, calibrate, and maintain exhaust gas composition monitors according to the requirements in 40 CFR 60.105a(b)(2) or 40 CFR 63.1572(c) or according to the manufacturer's specifications and requirements.

(h) Determine the mass of petroleum coke as required by Equation Y-13 of this subpart using mass measurement equipment meeting the requirements for commercial weighing equipment as described in Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44 (2009) (incorporated by reference, see §98.7). Calibrate the measurement device according to the procedures specified by NIST handbook 44 (incorporated by reference, see §98.7) or the procedures specified by the manufacturer. Recalibrate either biennially or at the minimum frequency specified by the manufacturer.

(i) Determine the carbon content of petroleum coke as required by Equation Y-13 of this subpart using any one of the following methods. Calibrate the measurement device according to procedures specified by the method or procedures specified by the measurement device manufacturer.

- (1) ASTM D3176-89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, see §98.7).
- (2) ASTM D5291-02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants (incorporated by reference, see §98.7).
- (3) ASTM D5373-08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, see §98.7).

(j) Determine the quantity of petroleum process streams using company records. These quantities include the quantity of asphalt blown, quantity of crude oil plus the quantity of intermediate products received from off site, and the quantity of unstabilized crude oil received at the facility.

(k) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of fuel usage, gas composition, and heating value including but not limited to calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices shall also be recorded, and the technical basis for these estimates shall be provided.

§98.255 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., concentrations, flow rates, fuel heating values, carbon content values). Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a CEMS malfunctions

during unit operation or if a required fuel sample is not taken), a substitute data value for the missing parameter shall be used in the calculations.

(a) For stationary combustion sources, use the missing data procedures in subpart C of this part.

(b) For each missing value of the heat content, carbon content, or molecular weight of the fuel, substitute the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. If the “after” value is not obtained by the end of the reporting year, you may use the “before” value for the missing data substitution. If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value obtained after the missing data period.

(c) For missing CO₂, CO, O₂, CH₄, or N₂O concentrations, gas flow rate, and percent moisture, the substitute data values shall be the best available estimate(s) of the parameter(s), based on all available process data (e.g., processing rates, operating hours, etc.). The owner or operator shall document and keep records of the procedures used for all such estimates.

(d) For hydrogen plants, use the missing data procedures in subpart P of this part.

§98.256 Data reporting requirements.

In addition to the reporting requirements of §98.3(c), you must report the information specified in paragraphs (a) through (q) of this section.

(a) For combustion sources, follow the data reporting requirements under subpart C of this part (General Stationary Fuel Combustion Sources).

(b) For hydrogen plants, follow the data reporting requirements under subpart P of this part (Hydrogen Production).

(c) [RESERVED].

(d) [RESERVED].

(e) For flares, owners and operators shall report:

(1) The flare ID number (if applicable).

(2) A description of the type of flare (steam assisted, air-assisted).

(3) A description of the flare service (general facility flare, unit flare, emergency only or back-up flare).

(4) The calculated CO₂, CH₄, and N₂O annual emissions for each flare, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO₂ emissions for each flare (e.g., reference section and equation number).

(6) If you use Equation Y-1 of this subpart, an indication of whether daily or weekly measurement periods are used, the annual volume of flare gas combusted (in scf/year) and the annual average molecular weight (in kg/kg-mole), the molar volume conversion factor (in scf/kg-mole), and annual average carbon content of the flare gas (in kg carbon per kg flare gas).

(7) If you use Equation Y-1b of this subpart, an indication of whether daily or weekly measurement periods are used, the annual volume of flare gas combusted (in scf/year), the molar volume conversion factor (in scf/kgmole), the annual average CO₂ concentration (volume or mole percent), the number of carbon containing compounds other than CO₂ in the flare gas stream, and for each of the carbon containing compounds other than CO₂ in the flare gas stream:

- (i) The annual average concentration of the compound (volume or mole percent).
 - (ii) The carbon mole number of the compound (moles carbon per mole compound).
- (8) If you use Equation Y-2 of this subpart, an indication of whether daily or weekly measurement periods are used, the annual volume of flare gas combusted (in million (MM) scf/year), the annual average higher heating value of the flare gas (in MMBtu per MMscf), and an indication of whether the annual volume of flare gas combusted and the annual average higher heating value of the flare gas were determined using standard conditions of 68 °F and 14.7 psia or 60 °F and 14.7 psia.
- (9) If you use Equation Y-3 of this subpart, the annual volume of flare gas combusted (in MMscf/year) during normal operations, the annual average higher heating value of the flare gas (in MMBtu/MMscf), the number of SSM events exceeding 500,000 scf/day, and the volume of gas flared (in scf/event), the average molecular weight (in kg/kg-mole), the molar volume conversion factor (in scf/kg-mole), and carbon content of the flare gas (in kg carbon per kg flare) for each SSM event over 500,000 scf/day.
- (10) The fraction of carbon in the flare gas contributed by methane used in Equation Y-4 of this subpart and the basis for its value.
- (f) For catalytic cracking units, traditional fluid coking units, and catalytic reforming units, owners and operators shall report:
- (1) The unit ID number (if applicable).
 - (2) A description of the type of unit (fluid catalytic cracking unit, thermal catalytic cracking unit, traditional fluid coking unit, or catalytic reforming unit).
 - (3) Maximum rated throughput of the unit, in bbl/stream day.
 - (4) The calculated CO₂, CH₄, and N₂O annual emissions for each unit, expressed in metric tons of each pollutant emitted.
 - (5) A description of the method used to calculate the CO₂ emissions for each unit (e.g., reference section and equation number).
 - (6) If you use a CEMS, the relevant information required under §98.36 for the Tier 4 Calculation Methodology, the CO₂ annual emissions as measured by the CEMS (unadjusted to remove CO₂ combustion emissions associated with additional units, if present) and the process CO₂ emissions as calculated according to §98.253(c)(1)(ii). Report the CO₂ annual emissions associated with sources other than those from the coke burn-off in the applicable subpart (e.g., subpart C of this part in the case of a CO boiler).
 - (7) If you use Equation Y-6 of this subpart, the annual average exhaust gas flow rate, %CO₂, %CO, and the molar volume conversion factor (in scf/kgmole).
 - (8) If you use Equation Y-7a of this subpart, the annual average flow rate of inlet air and oxygen-enriched air, %O₂, %O_{oxy}, %CO₂, and %CO.
 - (9) If you use Equation Y-7b of this subpart, the annual average flow rate of inlet air and oxygen-enriched air, %N_{2,oxy}, and %N_{2,exhaust}.
 - (10) If you use Equation Y-8 of this subpart, the coke burn-off factor, annual throughput of unit, and the average carbon content of coke and the basis for the value.
 - (11) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for CH₄ emissions. If you use a unit-specific emission factor for CH₄, report the unit-specific emission factor for CH₄, the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is

based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(12) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for N₂O emissions. If you use a unit-specific emission factor for N₂O, report the unit-specific emission factor for N₂O, the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.

(13) If you use Equation Y-11 of this subpart, the number of regeneration cycles or measurement periods during the reporting year, the average coke burn-off quantity per cycle or measurement period, and the average carbon content of the coke.

(g) For fluid coking unit of the flexicoking type, the owner or operator shall report:

(1) The unit ID number (if applicable).

(2) A description of the type of unit.

(3) Maximum rated throughput of the unit, in bbl/stream day.

(4) Indicate whether the GHG emissions from the low heat value gas are accounted for in subpart C of this part or §98.253(c).

(5) If the GHG emissions for the low heat value gas are calculated at the flexicoking unit, also report the calculated annual CO₂, CH₄, and N₂O emissions for each unit, expressed in metric tons of each pollutant emitted, and the applicable equation input parameters specified in paragraphs (f)(7) through (f)(13) of this section.

(h) For sulfur recovery plants and for emissions from sour gas sent off-site for sulfur recovery, the owner and operator shall report:

(1) The plant ID number (if applicable).

(2) Maximum rated throughput of each independent sulfur recovery plant, in metric tons sulfur produced/stream day, a description of the type of sulfur recovery plant, and an indication of the method used to calculate CO₂ annual emissions for the sulfur recovery plant (e.g., CO₂ CEMS, Equation Y-12, or process vent method in §98.253(j)).

(3) The calculated CO₂ annual emissions for each sulfur recovery plant, expressed in metric tons. The calculated annual CO₂ emissions from sour gas sent off-site for sulfur recovery, expressed in metric tons.

(4) If you use Equation Y-12 of this subpart, the annual volumetric flow to the sulfur recovery plant (in scf/year), the molar volume conversion factor (in scf/kg-mole), and the annual average mole fraction of carbon in the sour gas (in kg-mole C/kg-mole gas).

(5) If you recycle tail gas to the front of the sulfur recovery plant, indicate whether the recycled flow rate and carbon content are included in the measured data under §98.253(f)(2) and (3). Indicate whether a correction for CO₂ emissions in the tail gas was used in Equation Y-12. If so, then report the value of the correction, the annual volume of recycled tail gas (in scf/year) and the annual average mole fraction of carbon in the tail gas (in kg-mole C/kg-mole gas). Indicate whether you used the default (95%) or a unit specific correction, and if used, report the approach used.

(6) If you use a CEMS, the relevant information required under §98.36 for the Tier 4 Calculation Methodology, the CO₂ annual emissions as measured by the CEMS and the annual process CO₂ emissions calculated according to §98.253(f)(1). Report the CO₂

annual emissions associated with fuel combustion subpart C of this part (General Stationary Fuel Combustion Sources).

(7) If you use the process vent method in §98.253(j) for a non-Claus sulfur recovery plant, the relevant information required under paragraph (l)(5) of this section.

(i) For coke calcining units, the owner and operator shall report:

- (1) The unit ID number (if applicable).
- (2) Maximum rated throughput of the unit, in metric tons coke calcined/stream day.
- (3) The calculated CO₂, CH₄, and N₂O annual emissions for each unit, expressed in metric tons of each pollutant emitted.
- (4) A description of the method used to calculate the CO₂ emissions for each unit (e.g., reference section and equation number).
- (5) If you use Equation Y-13 of this subpart, annual mass and carbon content of green coke fed to the unit, the annual mass and carbon content of marketable coke produced, the annual mass of coke dust removed from the process through dust collection systems, and an indication of whether coke dust is recycled to the unit (e.g., all dust is recycled, a portion of the dust is recycled, or none of the dust is recycled).
- (6) If you use a CEMS, the relevant information required under §98.36 for the Tier 4 Calculation Methodology, the CO₂ annual emissions as measured by the CEMS and the annual process CO₂ emissions calculated according to §98.253(g)(1). Report the CO₂ annual emissions associated with fuel combustion under subpart C of this part (General Stationary Fuel Combustion Sources).
- (7) Indicate whether you use a measured value, a unit-specific emission factor or a default for CH₄ emissions. If you use a unit-specific emission factor for CH₄, the unit-specific emission factor for CH₄, the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis for the factor.
- (8) Indicate whether you use a measured value, a unit-specific emission factor, or a default emission factor for N₂O emissions, If you use a unit-specific emission factor for N₂O, report the unit-specific emission factor for N₂O, the units of measure for the unit-specific factor, the activity data for calculating emissions (e.g., if the emission factor is based on coke burn-off rate, the annual quantity of coke burned), and the basis of the factor.

(j) For asphalt blowing operations, the owner or operator shall report:

- (1) The unit ID number (if applicable).
- (2) The quantity of asphalt blown (in million bbl) at the unit in the reporting year.
- (3) The type of control device used to reduce methane (and other organic) emissions from the unit.
- (4) The calculated annual CO₂ and CH₄ emissions for each unit, expressed in metric tons of each pollutant emitted.
- (5) If you use Equation Y-14 of this subpart, the CO₂ emission factor used and the basis for the value.
- (6) If you use Equation Y-15 of this subpart, the CH₄ emission factor used and the basis for the value.

(7) If you use Equation Y-16 of this subpart, the carbon emission factor used and the basis for the value.

(8) If you use Equation Y-16b of this subpart, the CO₂ emission factor used and the basis for its value and the carbon emission factor used and the basis for its value.

(9) If you use Equation Y-17 of this subpart, the CH₄ emission factor used and the basis for the value.

(k) For delayed coking units, the owner or operator shall report:

(1) The cumulative annual CH₄ emissions (in metric tons of CH₄) for all delayed coking units at the facility.

(2) A description of the method used to calculate the CH₄ emissions for each unit (e.g., reference section and equation number).

(3) The total number of delayed coking units at the facility, the total number of delayed coking drums at the facility, and for each coke drum or vessel: the dimensions, the typical gauge pressure of the coking drum when first vented to the atmosphere, typical void fraction, the typical drum outage (i.e. the unfilled distance from the top of the drum, in feet), the molar volume conversion factor (in scf/kg-mole), and annual number of coke-cutting cycles.

(4) For each set of coking drums that are the same dimensions: the number of coking drums in the set, the height and diameter of the coke drums (in feet), the cumulative number of vessel openings for all delayed coking drums in the set, the typical venting pressure (in psig), void fraction (in cf gas/cf of vessel), and the mole fraction of methane in coking gas (in kg-mole CH₄/kg-mole gas, wet basis).

(5) The basis for the volumetric void fraction of the coke vessel prior to steaming and the basis for the mole fraction of methane in the coking gas.

(l) For each process vent subject to §98.253(j), the owner or operator shall report:

(1) The vent ID number (if applicable).

(2) The unit or operation associated with the emissions.

(3) The type of control device used to reduce methane (and other organic) emissions from the unit, if applicable.

(4) The calculated annual CO₂, CH₄, and N₂O emissions for each vent, expressed in metric tons of each pollutant emitted.

(5) The annual volumetric flow discharged to the atmosphere (in scf), and an indication of the measurement or estimation method, annual average mole fraction of each GHG above the concentration threshold or otherwise required to be reported and an indication of the measurement or estimation method, the molar volume conversion factor (in scf/kg-mole), and for intermittent vents, the number of venting events and the cumulative venting time.

(m) For uncontrolled blowdown systems, the owner or operator shall report:

(1) An indication of whether the uncontrolled blowdown emissions are reported under §98.253(k) or §98.253(j) or a statement that the facility does not have any uncontrolled blowdown systems.

(2) The cumulative annual CH₄ emissions (in metric tons of CH₄) for uncontrolled blowdown systems.

- (3) For uncontrolled blowdown systems reporting under §98.253(k), the total quantity (in million bbl) of crude oil plus the quantity of intermediate products received from off site that are processed at the facility in the reporting year, the methane emission factor used for uncontrolled blowdown systems, the basis for the value, and the molar volume conversion factor (in scf/kgmole).
 - (4) For uncontrolled blowdown systems reporting under §98.253(j), the relevant information required under paragraph (l)(5) of this section.
- (n) For equipment leaks, the owner or operator shall report:
- (1) The cumulative CH₄ emissions (in metric tons of each pollutant emitted) for all equipment leak sources.
 - (2) The method used to calculate the reported equipment leak emissions.
 - (3) The number of each type of emission source listed in Equation Y-21 of this subpart at the facility.
- (o) For storage tanks, the owner or operator shall report:
- (1) The cumulative annual CH₄ emissions (in metric tons of CH₄) for all storage tanks, except for those used to process unstabilized crude oil.
 - (2) For storage tanks other than those processing unstabilized crude oil:
 - (i) The method used to calculate the reported storage tank emissions for storage tanks other than those processing unstabilized crude (i.e., either AP-42, Section 7.1 (incorporated by reference, see §98.7), or Equation Y-22 of this section).
 - (ii) The total quantity (in MMbbl) of crude oil plus the quantity of intermediate products received from off-site that are processed at the facility in the reporting year.
 - (3) The cumulative CH₄ emissions (in metric tons of each CH₄) for storage tanks used to process unstabilized crude oil or a statement that the facility did not receive any unstabilized crude oil during the reporting year.
 - (4) For storage tanks that process unstabilized crude oil:
 - (i) The method used to calculate the reported unstabilized crude oil storage tank emissions.
 - (ii) The quantity of unstabilized crude oil received during the calendar year (in MMbbl).
 - (iii) The average pressure differential (in psi).
 - (iv) The molar volume conversion factor (in scf/kg-mole).
 - (v) The average mole fraction of CH₄ in vent gas from unstabilized crude oil storage tanks and the basis for the mole fraction.
 - (vi) If you did not use Equation Y-23, the tank-specific methane composition data and the gas generation rate data used to estimate the cumulative CH₄ emissions for storage tanks used to process unstabilized crude oil.
 - (5) The method used to calculate the reported storage tank emissions for storage tanks processing unstabilized crude oil.
 - (6) The quantity of unstabilized crude oil received during the calendar year (in MMbbl), the average pressure differential (in psi), and the mole fraction of CH₄ in vent gas from the unstabilized crude oil storage tank, and the basis for the mole fraction.

(7) The tank-specific methane composition data and the gas generation rate data, if you did not use Equation Y-23.

(p) For loading operations, the owner or operator shall report:

(1) The cumulative annual CH₄ emissions (in metric tons of each pollutant emitted) for loading operations.

(2) The quantity and types of materials loaded by vessel type (barge, tanker, marine vessel, etc.) that have an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, and the type of vessels in which the material is loaded.

(3) The type of control system used to reduce emissions from the loading of material with an equilibrium vapor-phase concentration of methane of 0.5 volume percent or greater, if any (submerged loading, vapor balancing, etc.).

(q) Name of each method listed in §98.254 or a description of manufacturer's recommended method used to determine a measured parameter.

§98.257 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records of all parameters monitored under §98.255. If you comply with the combustion methodology in §98.252(a), then you must retain under this subpart the records required for the Tier 3 and/or Tier 4 Calculation Methodologies in §98.37 and you must keep records of the annual average flow calculations.

§98.258 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.