(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.

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

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.

$$CH_4 = \left(995{,}000 \times Q_{un} \times \Delta P\right) \times MF_{CH4} \times \frac{16}{MVC} \times 0.001 \qquad \text{(Eq. Y-23)}$$

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_{CH4} = Average mole fraction of CH_4 in vent gas from the unstabilized crude oil storage tanks 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 CH_4 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 CH_4 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 vapor-phase concentration of methane is less than 0.5 volume percent, you may assume zero methane emissions.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79160, Dec. 17, 2010]

§ 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 CO_2 emissions according to subpart C of this part or that are associated with stationary combustion sources must meet the applicable monitoring and QA/QC requirements in § 98.34.

(b) All gas 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) and 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 $CO_2/CO/O_2$ 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.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79163, Dec. 17, 2010]

§ 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 CO_2, CO, O_2, CH_4, or N_2O 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)–(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 CO_2, CH_4, and N_2O annual emissions for each flare, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO_2 emissions for each flare (e.g., reference section and equation number).

(6) If you use Equation Y–1a 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/kg-mole), the annual average CO_2 concentration (volume or mole percent), the number of carbon containing compounds other than CO_2 in the flare gas stream, and for each of the carbon containing compounds other than CO_2 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