State	Compliance supplement pool
Delaware	168
District of Columbia	0
Indiana	2,454
Kentucky	7,314
Maryland	3,882
Michigan	9,398
New Jersey	1,550
New York	1,379
North Carolina	10,737
Ohio	22,301
Pennsylvania	15,763
Virginia	5,504
West Virginia	16,709
Total	97,159

PART 98—MANDATORY GREENHOUSE GAS REPORTING

Subpart A—General Provisions

Subpart B [Reserved]

Subpart C—General Stationary Fuel Combustion Sources

Subpart D—Electricity Generation

Subpart E—Adipic Acid Production

Subpart F—Aluminum Production

Subpart G—Ammonia Manufacturing

Subpart H—Cement Production

Subpart I—Electronics Manufacturing

Subpart J [Reserved]

Subpart K—Ferroalloy Production

Subpart L—Fluorinated Gas Production

Subpart –M [Reserved]

Subpart N—Glass Production

Subpart O—HCFC–22 Production and HFC–23 Destruction

Subpart P—Hydrogen Production

Subpart Q—Iron and Steel Production

Subpart R—Lead Production

Subpart S—Lime Manufacturing

Subpart T—Magnesium Production

Subpart U—Miscellaneous Uses of Carbonate

Subpart V—Nitric Acid Production

Subpart W—Petroleum and Natural Gas Systems

Subpart X—Petrochemical Production

Subpart Y—Petroleum Refineries

Subpart Z—Phosphoric Acid Production

Subpart AA—Pulp and Paper Manufacturing

Subpart BB—Silicon Carbide Production

Subpart CC—Soda Ash Manufacturing

Subpart DD—Electrical Transmission and Distribution Equipment Use

Subpart EE—Titanium Dioxide Production

Subpart FF—Underground Coal Mines

Subpart GG—Zinc Production

Subpart HH—Municipal Solid Waste Landfills

Subpart II—Industrial Wastewater Treatment

Subpart JJ—Manure Management

Subpart KK [Reserved]

Subpart LL—Suppliers of Coal-based Liquid Fuels

Subpart MM—Suppliers of Petroleum Products

Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids

Subpart OO—Suppliers of Industrial Greenhouse Gases

Subpart PP—Suppliers of Carbon Dioxide

Subpart QQ—Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment or Closed-Cell Foams

Subpart RR—Geologic Sequestration of Carbon Dioxide

Subpart SS—Electrical Equipment Manufacture or Refurbishment

Subpart TT—Industrial Waste Landfills

Subpart UU—Injection of Carbon Dioxide

AUTHORITY: 42 U.S.C. 7401, *et seq.*

SOURCE: 74 FR 56374, Oct. 30, 2009, unless otherwise noted.

Subpart A—General Provision

§ 98.1 Purpose and scope.

(a) This part establishes mandatory greenhouse gas (GHG) reporting requirements for owners and operators of certain facilities that directly emit GHG as well as for certain suppliers. For suppliers, the GHGs reported are the quantity that would be emitted from combustion or use of the products supplied.

(b) Owners and operators of facilities and suppliers that are subject to this part must follow the requirements of this subpart and all applicable subparts of this part. If a conflict exists between a provision in subpart A and any other applicable subpart, the requirements of the applicable subpart shall take precedence.

(c) For facilities required to report under onshore petroleum and natural gas production under subpart W of this part, the terms *Owner* and *Operator* used in subpart A have the same definition as *Onshore petroleum and natural gas production owner or operator*, as defined in § 98.238 of this part.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 39758, July 12, 2010; 76 FR 73898, Nov. 29, 2011; 76 FR 80573, Dec. 23, 2011]

§ 98.2 Who must report?

(a) The GHG reporting requirements and related monitoring, recordkeeping, and reporting requirements of this part apply to the owners and operators of any facility that is located in the United States or under or attached to the Outer Continental Shelf (as defined in 43 U.S.C. 1331) and that meets the requirements of either paragraph (a)(1), (a)(2), or (a)(3) of this section; and any supplier that meets the requirements of paragraph (a)(4) of this section:

(1) *A facility that contains any source category that is listed in Table A–3 of this subpart in any calendar year starting in 2010*. For these facilities, the annual GHG report must cover stationary fuel combustion sources (subpart C of this part), miscellaneous use of carbonates (subpart U of this part), and all applicable source categories listed in Table A–3 and Table A–4 of this subpart.

(2) *A facility that contains any source category that is listed in Table A–4 of this subpart and that emits 25,000 metric tons CO_2e or more per year in combined emissions from stationary fuel combustion units, miscellaneous uses of carbonate, and all applicable source categories that are listed in Table A–3 and Table A–4 of this subpart*. For these facilities, the

annual GHG report must cover stationary fuel combustion sources (subpart C of this part), miscellaneous use of carbonates (subpart U of this part), and all applicable source categories listed in Table A–3 and Table A–4 of this subpart.

(3) *A facility that in any calendar year starting in 2010 meets all three of the conditions listed in this paragraph (a)(3).* For these facilities, the annual GHG report must cover emissions from stationary fuel combustion sources only.

(i) The facility does not meet the requirements of either paragraph (a)(1) or (a)(2) of this section.

(ii) The aggregate maximum rated heat input capacity of the stationary fuel combustion units at the facility is 30 mmBtu/hr or greater.

(iii) The facility emits 25,000 metric tons CO_2e or more per year in combined emissions from all stationary fuel combustion sources.

(4) *A supplier that is listed in Table A–5 of this subpart.* For these suppliers, the annual GHG report must cover all applicable products for which calculation methodologies are provided in the subparts listed in Table A–5 of this subpart.

(5) Research and development activities are not considered to be part of any source category defined in this part.

(b) To calculate GHG emissions for comparison to the 25,000 metric ton CO_2e per year emission threshold in paragraph (a)(2) of this section, the owner or operator shall calculate annual CO_2e emissions, as described in paragraphs (b)(1) through (b)(4) of this section.

(1) Calculate the annual emissions of CO_2, CH_4, N_2O,and each fluorinated GHG in metric tons from all applicable source categories listed in paragraph (a)(2) of this section. The GHG emissions shall be calculated using the calculation methodologies specified in each applicable subpart and available company records. Include emissions from only those gases listed in Table A–1 of this subpart.

(2) For each general stationary fuel combustion unit, calculate the annual CO_2 emissions in metric tons using any of the four calculation methodologies specified in § 98.33(a). Calculate the annual CH_4 and N_2O emissions from the stationary fuel combustion sources in metric tons using the appropriate equation in § 98.33(c). Exclude carbon dioxide emissions from the combustion of biomass, but include emissions of CH_4 and N_2O from biomass combustion.

(3) For miscellaneous uses of carbonate, calculate the annual CO_2 emissions in metric tons using the procedures specified in subpart U of this part.

(4) Sum the emissions estimates from paragraphs (b)(1), (b)(2), and (b)(3) of this section for each GHG and calculate metric tons of CO_2e using Equation A–1 of this section.

$$CO_2e = \sum_{i=1}^{n} GHG_i \times GWP_i \qquad \text{(Eq. A-1)}$$

Where:

CO_2e = Carbon dioxide equivalent, metric tons/year.

GHG_i = Mass emissions of each greenhouse gas listed in Table A–1 of this subpart, metric tons/year.

GWP_i = Global warming potential for each greenhouse gas from Table A–1 of this subpart.

n = The number of greenhouse gases emitted.

(5) For purpose of determining if an emission threshold has been exceeded, include in the emissions calculation any CO_2 that is captured for transfer off site.

(c) To calculate GHG emissions for comparison to the 25,000 metric ton CO_2e/year emission threshold for stationary fuel combustion under paragraph (a)(3) of this section, calculate CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit by following the methods specified in paragraph (b)(2) of this section. Then, convert the emissions of each GHG to metric tons CO_2e per year using Equation A–1 of this section, and sum the emissions for all units at the facility.

(d) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2 per year threshold for importers and exporters of coal-to-liquid products under paragraph (a)(4) of this section, calculate the mass in metric tons per year of CO_2 that would result from the complete combustion or oxidation of the quantity of coal-to-liquid products that are imported during the reporting year and, that are exported during the reporting year. Compare the imported quantities and the exported quantities separately to the 25,000 metric ton CO_2 per year threshold. Calculate the quantities using the methodology specified in subpart LL of this part.

(e) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2e per year threshold for importers and exporters of petroleum products under paragraph (a)(4) of this section, calculate the mass in metric tons per year of CO_2 that would result from the complete combustion or oxidation of the combined volume of petroleum products and natural gas liquids that are imported during the reporting year and that are exported during the reporting year. Compare the imported quantities and the exported quantities separately to the 25,000 metric ton CO_2 per year threshold. Calculate the quantities using the methodology specified in subpart MM of this part.

(f) To calculate GHG quantities for comparison to the 25,000 metric ton CO_2e per year threshold under paragraph (a)(4) of this section for importers and exporters of industrial greenhouse gases and for importers and exporters of CO_2, the owner or operator shall calculate the mass in metric tons per year of CO_2e imports and exports as described in paragraphs (f)(1) through (f)(3) of this section. Compare the imported quantities and the exported quantities separately to the 25,000 metric ton CO_2 per year threshold.

(1) Calculate the mass in metric tons per year of CO_2, N_2O, and each fluorinated GHG that is imported and the mass in metric tons per year of CO_2, N_2O, and each fluorinated GHG that is exported during the year. Include only those gases listed in Table A–1 of this subpart.

(2) Convert the mass of each imported and each GHG exported from paragraph (f)(1) of this section to metric tons of CO_2e using Equation A–1 of this section.

(3) Sum the total annual metric tons of CO_2e in paragraph (f)(2) of this section for all imported GHGs. Sum the total annual metric tons of CO_2e in paragraph (f)(2) of this section for all exported GHGs.

(g) If a capacity or generation reporting threshold in paragraph (a)(1) of this section applies, the owner or operator shall review the appropriate records and perform any necessary calculations to determine whether the threshold has been exceeded.

(h) An owner or operator of a facility or supplier that does not meet the applicability requirements of paragraph (a) of this section is not subject to this rule. Such owner or operator would become subject to the rule and reporting requirements, if a facility or supplier exceeds the applicability requirements of paragraph (a) of this section at a later time pursuant to § 98.3(b)(3). Thus, the owner or operator should reevaluate the applicability to this part (including the revising of any relevant emissions calculations or other calculations) whenever there is any change that could cause a facility or supplier to meet the applicability requirements of paragraph (a) of this section. Such changes include but are not limited to process modifications, increases in operating hours, increases in production, changes in fuel or raw material use, addition of equipment, and facility expansion.

(i) Except as provided in this paragraph, once a facility or supplier is subject to the requirements of this part, the owner or operator must continue for each year thereafter to comply with all requirements of this part, including the requirement to submit annual GHG reports, even if the facility or supplier does not meet the applicability requirements in paragraph (a) of this section in a future year.

(1) If reported emissions are less than 25,000 metric tons CO_2e per year for five consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the fifth consecutive year of emissions less than 25,000 tons CO_2e per year. The owner or operator must maintain the corresponding records required under § 98.3(g) for each of the five consecutive years and retain

such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual emissions in any future calendar year increase to 25,000 metric tons CO_2e per year or more.

(2) If reported emissions are less than 15,000 metric tons CO_2e per year for three consecutive years, then the owner or operator may discontinue complying with this part provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and explains the reasons for the reduction in emissions. The notification shall be submitted no later than March 31 of the year immediately following the third consecutive year of emissions less than 15,000 tons CO_2e per year. The owner or operator must maintain the corresponding records required under § 98.3(g) for each of the three consecutive years and retain such records for three years following the year that reporting was discontinued. The owner or operator must resume reporting if annual emissions in any future calendar year increase to 25,000 metric tons CO_2e per year or more.

(3) If the operations of a facility or supplier are changed such that all applicable GHG-emitting processes and operations listed in paragraphs (a)(1) through (a)(4) of this section cease to operate, then the owner or operator is exempt from reporting in the years following the year in which cessation of such operations occurs, provided that the owner or operator submits a notification to the Administrator that announces the cessation of reporting and certifies to the closure of all GHG-emitting processes and operations no later than March 31 of the year following such changes. This paragraph (i)(3) does not apply to seasonal or other temporary cessation of operations. This paragraph (i)(3) does not apply to facilities with municipal solid waste landfills or industrial waste landfills, or to underground coal mines. The owner or operator must resume reporting for any future calendar year during which any of the GHG-emitting processes or operations resume operation.

(j) Table A–2 of this subpart provides a conversion table for some of the common units of measure used in part 98.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 39758, July 12, 2010; 75 FR 57685, Sept. 22, 2010; 76 FR 73899, Nov. 29, 2011; 75 FR 74487, Nov. 30, 2010]

§ 98.3 What are the general monitoring, reporting, recordkeeping and verification requirements of this part?

The owner or operator of a facility or supplier that is subject to the requirements of this part must submit GHG reports to the Administrator, as specified in this section.

(a) *General.* Except as provided in paragraph (d) of this section, follow the procedures for emission calculation, monitoring, quality assurance, missing data, recordkeeping, and reporting that are specified in each relevant subpart of this part.

(b) *Schedule.* The annual GHG report for reporting year 2010 must be submitted no later than September 30, 2011. The annual report for reporting years 2011 and beyond must be submitted no later than March 31 of each calendar year for GHG emissions in the previous calendar year, except as provided in paragraph (b)(1) of this section.

(1) For reporting year 2011, facilities with one or more of the subparts listed in paragraphs (b)(1)(i) through (b)(1)(xi) of this section and suppliers listed in paragraph (b)(1)(xii) of this section are required to submit their annual GHG report no later than September 28, 2012. Facilities and suppliers that are submitting their second annual GHG report in 2012 and that are reporting on one or more subparts listed in paragraphs (b)(1)(i) through (b)(1)(xii) of this section must notify EPA by March 31, 2012 that they are not required to submit their annual GHG report until September 28, 2012.

(i) Electronics Manufacturing (subpart I).

(ii) Fluorinated Gas Production (subpart L).

(iii) Magnesium Production (subpart T).

(iv) Petroleum and Natural Gas Systems (subpart W).

(v) Use of Electric Transmission and Distribution Equipment (subpart DD).

(vi) Underground Coal Mines (subpart FF).

(vii) Industrial Wastewater Treatment (subpart II).

(viii) Geologic Sequestration of Carbon Dioxide (subpart RR).

(ix) Manufacture of Electric Transmission and Distribution (subpart SS).

(x) Industrial Waste Landfills (subpart TT).

(xi) Injection of Carbon Dioxide (subpart UU).

(xii) Imports and Exports of Equipment Pre-charged with Fluorinated GHGs or Containing Fluorinated GHGs in Closed-cell Foams (subpart QQ).

(2) For a new facility or supplier that begins operation on or after January 1, 2010 and becomes subject to the rule in the year that it becomes operational, report emissions beginning with the first operating month and ending on December 31 of that year. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(3) For any facility or supplier that becomes subject to this rule because of a physical or operational change that is made after January 1, 2010, report emissions for the first calendar year in which the change occurs, beginning with the first month of the change and ending on December 31 of that year. For a facility or supplier that becomes subject to this rule solely because of an increase in hours of operation or level of production, the first month of the change is the month in which the increased hours of operation or level of production, if maintained for the remainder of the year, would cause the facility or supplier to exceed the applicable threshold. Each subsequent annual report must cover emissions for the calendar year, beginning on January 1 and ending on December 31.

(4) Unless otherwise stated, if the final day of any time period falls on a weekend or a federal holiday, the time period shall be extended to the next business day.

(c) *Content of the annual report.* Except as provided in paragraph (d) of this section, each annual GHG report shall contain the following information:

(1) Facility name or supplier name (as appropriate), and physical street address of the facility or supplier, including the city, State, and zip code. If the facility does not have a physical street address, then the facility must provide the latitude and longitude representing the geographic centroid or center point of facility operations in decimal degree format. This must be provided in a comma-delimited ‘‘latitude, longitude’’ coordinate pair reported in decimal degrees to at least four digits to the right of the decimal point.

(2) Year and months covered by the report.

(3) Date of submittal.

(4) For facilities, except as otherwise provided in paragraph (c)(12) of this section, report annual emissions of CO_2, CH_4, N_2O, each fluorinated GHG (as defined in § 98.6), and each fluorinated heat transfer fluid (as defined in § 98.98) as follows.

(i) Annual emissions (excluding biogenic CO_2) aggregated for all GHG from all applicable source categories, expressed in metric tons of CO_2e calculated using Equation A–1 of this subpart. For electronics manufacturing (as defined in § 98.90), starting in reporting year 2012 the CO_2e calculation must include each fluorinated heat transfer fluid (as defined in § 98.98) whether or not it is also a fluorinated GHG.

(ii) Annual emissions of biogenic CO_2 aggregated for all applicable source categories, expressed in metric tons.

(iii) Annual emissions from each applicable source category, expressed in metric tons of each applicable GHG listed in paragraphs (c)(4)(iii)(A) through (c)(4)(iii)(E) of this section.

(A) Biogenic CO_2.

(B) CO_2 (excluding biogenic CO_2).

(C) CH_4.

(D) N_2O.

(E) Each fluorinated GHG (as defined in § 98.6), including those not listed in Table A–1 of this subpart.

(F) For electronics manufacturing (as defined in § 98.90), each fluorinated heat transfer fluid (as defined in § 98.98) that is not also a fluorinated GHG as specified under (c)(4)(iii)(E) of this section.

This requirement applies beginning in reporting year 2012.

(iv) Except as provided in paragraph (c)(4)(vii) of this section, emissions and other data for individual units, processes, activities, and operations as specified in the ‘‘Data reporting requirements’’ section of each applicable subpart of this part.

(v) Indicate (yes or no) whether reported emissions include emissions from a cogeneration unit located at the facility.

(vi) When applying paragraph (c)(4)(i) of this section to fluorinated GHGs and fluorinated heat transfer fluids, calculate and report CO_2e for only those fluorinated GHGs and fluorinated heat transfer fluids listed in Table A–1 of this subpart.

(vii) The owner or operator of a facility is not required to report the data elements specified in Table A–6 to this subpart for calendar years 2010 through 2011 until March 31, 2013. The owner or operator of a facility is not required to report the data elements specified in Table A–7 to this subpart for calendar years 2010 through 2013 until March 31, 2015.

(viii) Applicable source categories means stationary fuel combustion sources (subpart C of this part), miscellaneous use of carbonates (subpart U of this part), and all of the source categories listed in Table A–3 and Table A–4 of this subpart present at the facility.

(5) For suppliers, report annual quantities of CO_2, CH_4, N_2O, and each fluorinated GHG (as defined in § 98.6) that would be emitted from combustion or use of the products supplied, imported, and exported during the year. Calculate and report quantities at the following levels:

(i) Total quantity of GHG aggregated for all GHG from all applicable supply categories in Table A–5 of this subpart and expressed in metric tons of CO_2e calculated using Equation A–1 of this subpart. For fluorinated GHGs, calculate and report CO_2e for only those fluorinated GHGs listed in Table A–1 of this subpart.

(ii) Quantity of each GHG from each applicable supply category in Table A–5 to this subpart, expressed in metric tons of each GHG. For fluorinated GHG, report quantities of all fluorinated GHG, including those not listed in Table A–1 to this subpart.

(iii) Any other data specified in the ‘‘Data reporting requirements’’ section of each applicable subpart of this part.

(6) A written explanation, as required under § 98.3(e), if you change emission calculation methodologies during the reporting period.

(7) A brief description of each ‘‘best available monitoring method’’ used, the parameter measured using the method, and the time period during which the ‘‘best available monitoring method’’ was used, if applicable.

(8) Each data element for which a missing data procedure was used according to the procedures of an applicable subpart and the total number of hours in the year that a missing data procedure was used for each data element.

(9) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of § 98.4(e)(1).

(10) NAICS code(s) that apply to the facility or supplier.

(i) *Primary NAICS code.* Report the NAICS code that most accurately describes the facility or supplier’s primary product/activity/service. The primary product/activity/service is the principal source of revenue for the facility or supplier. A facility or supplier that has two distinct products/activities/services providing comparable revenue may report a second primary NAICS code.

(ii) *Additional NAICS code(s).* Report all additional NAICS codes that describe all product(s)/activity(s)/service(s) at the facility or supplier that are not related to the principal source of revenue.

(11) Legal name(s) and physical address(es) of the highest-level United States parent company(s) of the owners (or operators) of the facility or supplier and the percentage of ownership interest for each listed parent company as of December 31 of the year for which data are being reported according to the following instructions:

(i) If the facility or supplier is entirely owned by a single United States company that is not owned by another company, provide that company's legal name and physical address as the United States parent company and report 100 percent ownership.

(ii) If the facility or supplier is entirely owned by a single United States company that is, itself, owned by another company (*e.g.*, it is a division or subsidiary of a higher-level company), provide the legal name and physical address of the highest-level company in the ownership hierarchy as the United States parent company and report 100 percent ownership.

(iii) If the facility or supplier is owned by more than one United States company (*e.g.*, company A owns 40 percent, company B owns 35 percent, and company C owns 25 percent), provide the legal names and physical addresses of all the highest-level companies with an ownership interest as the United States parent companies, and report the percent ownership of each company.

(iv) If the facility or supplier is owned by a joint venture or a cooperative, the joint venture or cooperative is its own United States parent company. Provide the legal name and physical address of the joint venture or cooperative as the United States parent company, and report 100 percent ownership by the joint venture or cooperative.

(v) If the facility or supplier is entirely owned by a foreign company, provide the legal name and physical address of the foreign company's highest-level company based in the United States as the United States parent company, and report 100 percent ownership.

(vi) If the facility or supplier is partially owned by a foreign company and partially owned by one or more U.S. companies, provide the legal name and physical address of the foreign company's highest-level company based in the United States, along with the legal names and physical addresses of the other U.S. parent companies, and report the percent ownership of each of these companies.

(vii) If the facility or supplier is a federally owned facility, report ''U.S. Government'' and do not report physical address or percent ownership.

(viii) The facility or supplier must refer to the reporting instructions of the electronic GHG reporting tool regarding standardized conventions for the naming of a parent company.

(12) For the 2010 reporting year only, facilities that have ''part 75 units'' (*i.e.* units that are subject to subpart D of this part or units that use the methods in part 75 of this chapter to quantify CO_2 mass emissions in accordance with § 98.33(a)(5)) must report annual GHG emissions either in full accordance with paragraphs (c)(4)(i) through (c)(4)(iii) of this section or in full accordance with paragraphs (c)(12)(i) through (c)(12)(iii) of this section. If the latter reporting option is chosen, you must report:

(i) Annual emissions aggregated for all GHG from all applicable source categories, expressed in metric tons of CO_2e calculated using Equation A–1 of this subpart. You must include biogenic CO_2 emissions from part 75 units in these annual emissions, but exclude biogenic CO_2 emissions from any non-part 75 units and other source categories.

(ii) Annual emissions of biogenic CO_2, expressed in metric tons (excluding biogenic CO_2 emissions from part 75 units), aggregated for all applicable source categories.

(iii) Annual emissions from each applicable source category, expressed in metric tons of each applicable GHG listed in paragraphs (c)(12)(iii)(A) through (c)(12)(iii)(E) of this section.

(A) Biogenic CO_2 (excluding biogenic CO_2 emissions from part 75 units).

(B) CO_2. You must include biogenic CO_2 emissions from part 75 units in these totals and exclude biogenic CO_2 emissions from other non-part 75 units and other source categories.

(C) CH_4.

(D) N_2O.

(E) Each fluorinated GHG (including those not listed in Table A–1 of this subpart).

(13) An indication of whether the facility includes one or more plant sites that have been assigned a ''plant code'' (as defined under § 98.6) by either the Department of Energy's Energy Information Administration or by the EPA's Clean Air Markets Division.

(d) *Special provisions for reporting year 2010.* (1) *Best available monitoring methods.* During January 1, 2010 through

March 31, 2010, owners or operators may use best available monitoring methods for any parameter (e.g., fuel use, daily carbon content of feedstock by process line) that cannot reasonably be measured according to the monitoring and QA/QC requirements of a relevant subpart. The owner or operator must use the calculation methodologies and equations in the ''Calculating GHG Emissions'' sections of each relevant subpart, but may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2010. Starting no later than April 1, 2010, the owner or operator must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraphs (d)(2) and (d)(3) of this section. Best available monitoring methods means any of the following methods specified in this paragraph:

(i) Monitoring methods currently used by the facility that do not meet the specifications of an relevant subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) *Requests for extension of the use of best available monitoring methods.* The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods beyond March 31, 2010.

(i) *Timing of request.* The extension request must be submitted to EPA no later than 30 days after the effective date of the GHG reporting rule.

(ii) *Content of request.* Requests must contain the following information:

(A) A list of specific item of monitoring instrumentation for which the request is being made and the locations where each piece of monitoring instrumentation will be installed.

(B) Identification of the specific rule requirements (by rule subpart, section, and paragraph numbers) for which the instrumentation is needed.

(C) A description of the reasons why the needed equipment could not be obtained and installed before April 1, 2010.

(D) If the reason for the extension is that the equipment cannot be purchased and delivered by April 1, 2010, include supporting documentation such as the date the monitoring equipment was ordered, investigation of alternative suppliers and the dates by which alternative vendors promised delivery, backorder notices or unexpected delays, descriptions of actions taken to expedite delivery, and the current expected date of delivery.

(E) If the reason for the extension is that the equipment cannot be installed without a process unit shutdown, include supporting documentation demonstrating that it is not practicable to isolate the equipment and install the monitoring instrument without a full process unit shutdown. Include the date of the most recent process unit shutdown, the frequency of shutdowns for this process unit, and the date of the next planned shutdown during which the monitoring equipment can be installed. If there has been a shutdown or if there is a planned process unit shutdown between promulgation of this part and April 1, 2010, include a justification of why the equipment could not be obtained and installed during that shutdown.

(F) A description of the specific actions the facility will take to obtain and install the equipment as soon as reasonably feasible and the expected date by which the equipment will be installed and operating.

(iii) *Approval criteria.* To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2010. The use of best available methods will not be approved beyond December 31, 2010.

(3) *Abbreviated emissions report for facilities containing only general stationary fuel combustion sources.* In lieu of the report required by paragraph (c) of this section, the owner or operator of an existing facility that is in operation on January 1, 2010 and that meets the conditions of §98.2(a)(3) may submit an abbreviated GHG report for the facility for GHGs emitted in 2010. The abbreviated report must be submitted by

September 30, 2011. An owner or operator that submits an abbreviated report must submit a full GHG report according to the requirements of paragraph (c) of this section beginning in calendar year 2012. The abbreviated facility report must include the following information:

(i) Facility name and physical street address including the city, state and zip code.

(ii) The year and months covered by the report.

(iii) Date of submittal.

(iv) Total facility GHG emissions aggregated for all stationary fuel combustion units calculated according to any method specified in § 98.33(a) and expressed in metric tons of CO_2, CH_4, N_2O, and CO_2e.

(v) Any facility operating data or process information used for the GHG emission calculations.

(vi) A signed and dated certification statement provided by the designated representative of the owner or operator, according to the requirements of paragraph (e)(1) of this section.

(e) *Emission calculations*. In preparing the GHG report, you must use the calculation methodologies specified in the relevant subparts, except as specified in paragraph (d) of this section. For each source category, you must use the same calculation methodology throughout a reporting period unless you provide a written explanation of why a change in methodology was required.

(f) *Verification*. To verify the completeness and accuracy of reported GHG emissions, the Administrator may review the certification statements described in paragraphs (c)(9) and (d)(3)(vi) of this section and any other credible evidence, in conjunction with a comprehensive review of the GHG reports and periodic audits of selected reporting facilities. Nothing in this section prohibits the Administrator from using additional information to verify the completeness and accuracy of the reports.

(g) *Recordkeeping*. An owner or operator that is required to report GHGs under this part must keep records as specified in this paragraph. Retain all required records for at least 3 years. Retain all required records for at least 3 years from the date of submission of the annual GHG report for the reporting year in which the record was generated. Upon request by the Administrator, the records required under this section must be made available to EPA. Records may be retained off site if the records are readily available for expeditious inspection and review. For records that are electronically generated or maintained, the equipment or software necessary to read the records shall be made available, or, if requested by EPA, electronic records shall be converted to paper documents. You must retain the following records, in addition to those records prescribed in each applicable subpart of this part:

(1) A list of all units, operations, processes, and activities for which GHG emission were calculated.

(2) The data used to calculate the GHG emissions for each unit, operation, process, and activity, categorized by fuel or material type. These data include but are not limited to the following information in this paragraph (g)(2):

(i) The GHG emissions calculations and methods used.

(ii) Analytical results for the development of site-specific emissions factors.

(iii) The results of all required analyses for high heat value, carbon content, and other required fuel or feedstock parameters.

(iv) Any facility operating data or process information used for the GHG emission calculations.

(3) The annual GHG reports.

(4) Missing data computations. For each missing data event, also retain a record of the cause of the event and the corrective actions taken to restore malfunctioning monitoring equipment.

(5) A written GHG Monitoring Plan.

(i) At a minimum, the GHG Monitoring Plan shall include the elements listed in this paragraph (g)(5)(i).

(A) Identification of positions of responsibility (i.e., job titles) for collection of the emissions data.

(B) Explanation of the processes and methods used to collect the necessary data for the GHG calculations.

(C) Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(ii) The GHG Monitoring Plan may rely on references to existing corporate documents (e.g., standard operating procedures, quality assurance programs under appendix F to 40 CFR part 60 or appendix B to 40 CFR part 75, and other documents) provided that the elements required by paragraph (g)(5)(i) of this section are easily recognizable.

(iii) The owner or operator shall revise the GHG Monitoring Plan as needed to reflect changes in production processes, monitoring instrumentation, and quality assurance procedures; or to improve procedures for the maintenance and repair of monitoring systems to reduce the frequency of monitoring equipment downtime.

(iv) Upon request by the Administrator, the owner or operator shall make all information that is collected in conformance with the GHG Monitoring Plan available for review during an audit. Electronic storage of the information in the plan is permissible, provided that the information can be made available in hard copy upon request during an audit.

(6) The results of all required certification and quality assurance tests of continuous monitoring systems, fuel flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(7) Maintenance records for all continuous monitoring systems, flow meters, and other instrumentation used to provide data for the GHGs reported under this part.

(h) *Annual GHG report revisions.* (1) The owner or operator shall submit a revised annual GHG report within 45 days of discovering that an annual GHG report that the owner or operator previously submitted contains one or more substantive errors. The revised report must correct all substantive errors.

(2) The Administrator may notify the owner or operator in writing that an annual GHG report previously submitted by the owner or operator contains one or more substantive errors. Such notification will identify each such substantive error. The owner or operator shall, within 45 days of receipt of the notification, either resubmit the report that, for each identified substantive error, corrects the identified substantive error (in accordance with the applicable requirements of this part) or provide information demonstrating that the previously submitted report does not contain the identified substantive error or that the identified error is not a substantive error.

(3) A substantive error is an error that impacts the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified.

(4) Notwithstanding paragraphs (h)(1) and (2) of this section, upon request by the owner or operator, the Administrator may provide reasonable extensions of the 45-day period for submission of the revised report or information under paragraphs (h)(1) and (2) of this section. If the Administrator receives a request for extension of the 45-day period, by email to an address prescribed by the Administrator prior to the expiration of the 45-day period, the extension request is deemed to be automatically granted for 30 days. The Administrator may grant an additional extension beyond the automatic 30-day extension if the owner or operator submits a request for an additional extension and the request is received by the Administrator at least 5 business days prior to the expiration of the automatic 30-day extension, provided the request demonstrates that it is not practicable to submit a revised report or information under paragraphs (h)(1) and (2) within 75 days. The Administrator will approve the extension request if the request demonstrates to the Administrator's satisfaction that it is not practicable to collect and process the data needed to resolve potential reporting errors identified pursuant to paragraphs (h)(1) or (2) of this section within 75 days.

(5) The owner or operator shall retain documentation for 3 years to support any revision made to an annual GHG report.

(i) *Calibration accuracy requirements.* The owner or operator of a facility or supplier that is subject to the requirements of this part must meet the applicable flow meter calibration and accuracy requirements of this paragraph (i). The accuracy specifications in this paragraph (i) do not apply where either the use of company records (as defined in § 98.6) or the use of ''best available information'' is specified in an applicable subpart of this part to quantify fuel usage and/or other parameters. Further, the provisions of this paragraph (i) do not apply to stationary fuel combustion units that use the methodologies in part 75 of this chapter to calculate CO_2 mass emissions.

(1) Except as otherwise provided in paragraphs (i)(4) through (i)(6) of this section, flow meters that measure liquid and gaseous fuel feed rates, process stream flow rates, or feedstock flow rates and provide data for the GHG emissions calculations shall be calibrated prior to April 1, 2010 using the procedures specified in this paragraph (i) when such calibration is specified in a relevant subpart of this part. Each of these flow meters shall meet the applicable accuracy specification in paragraph (i)(2) or (i)(3) of this section. All other measurement devices (*e.g.*, weighing devices) that are required by a relevant subpart of this part, and that are used to provide data for the GHG emissions calculations, shall also be calibrated prior to April 1, 2010; however, the accuracy specifications in paragraphs (i)(2) and (i)(3) of this section do not apply to these devices. Rather, each of these measurement devices shall be calibrated to meet the accuracy requirement specified for the device in the applicable subpart of this part, or, in the absence of such accuracy requirement, the device must be calibrated to an accuracy within the appropriate error range for the specific measurement technology, based on an applicable operating standard, including but not limited to manufacturer's specifications and industry standards. The procedures and methods used to quality-assure the data from each measurement device shall be documented in the written monitoring plan, pursuant to paragraph (g)(5)(i)(C) of this section.

(i) All flow meters and other measurement devices that are subject to the provisions of this paragraph (i) must be calibrated according to one of the following: You may use the manufacturer's recommended procedures; an appropriate industry consensus standard method; or a method specified in a relevant subpart of this part. The calibration method(s) used shall be documented in the monitoring plan required under paragraph (g) of this section.

(ii) For facilities and suppliers that become subject to this part after April 1, 2010, all flow meters and other measurement devices (if any) that are required by the relevant subpart(s) of this part to provide data for the GHG emissions calculations shall be installed no later than the date on which data collection is required to begin using the measurement device, and the initial calibration(s) required by this paragraph (i) (if any) shall be performed no later than that date.

(iii) Except as otherwise provided in paragraphs (i)(4) through (i)(6) of this section, subsequent recalibrations of the flow meters and other measurement devices subject to the requirements of this paragraph (i) shall be performed at one of the following frequencies:

(A) You may use the frequency specified in each applicable subpart of this part.

(B) You may use the frequency recommended by the manufacturer or by an industry consensus standard practice, if no recalibration frequency is specified in an applicable subpart.

(2) Perform all flow meter calibration at measurement points that are representative of the normal operating range of the meter. Except for the orifice, nozzle, and venturi flow meters described in paragraph (i)(3) of this section, calculate the calibration error at each measurement point using Equation A–2 of this section. The terms ''R'' and ''A'' in Equation A–2 must be expressed in consistent units of measure (*e.g.*, gallons/minute, ft^3/min). The calibration error at each measurement point shall not exceed 5.0 percent of the reference value.

$$CE = \frac{|R - A|}{R} \; x \; 100 \qquad \text{(Eq. A-2)}$$

where:
CE = Calibration error (%).
R = Reference value.
A = Flow meter response to the reference value.

(3) For orifice, nozzle, and venturi flow meters, the initial quality assurance consists of in-situ calibration of the differential pressure (delta-P), total pressure, and temperature transmitters.

(i) Calibrate each transmitter at a zero point and at least one upscale point. Fixed reference points, such as the freezing point of water, may be used for temperature transmitter calibrations. Calculate the calibration error of each transmitter at each measurement point, using Equation A–3 of this subpart. The terms "R," "A," and "FS" in Equation A–3 of this subpart must be in consistent units of measure (*e.g.*, milliamperes, inches of water, psi, degrees). For each transmitter, the CE value at each measurement point shall not exceed 2.0 percent of full-scale. Alternatively, the results are acceptable if the sum of the calculated CE values for the three transmitters at each calibration level (*i.e.*, at the zero level and at each upscale level) does not exceed 6.0 percent.

$$CE = \frac{|R - A|}{FS} \; x \; 100 \qquad \text{(Eq. A-3)}$$

where:
CE = Calibration error (%).
R = Reference value.
A = Transmitter response to the reference value.
FS = Full-scale value of the transmitter.

(ii) In cases where there are only two transmitters (*i.e.*, differential pressure and either temperature or total pressure) in the immediate vicinity of the flow meter's primary element (*e.g.*, the orifice plate), or when there is only a differential pressure transmitter in close proximity to the primary element, calibration of these existing transmitters to a CE of 2.0 percent or less at each measurement point is still required, in accordance with paragraph (i)(3)(i) of this section; alternatively, when two transmitters are calibrated, the results are acceptable if the sum of the CE values for the two transmitters at each calibration level does not exceed 4.0 percent. However, note that installation and calibration of an additional transmitter (or transmitters) at the flow monitor location to measure temperature or total pressure or both is not required in these cases. Instead, you may use assumed values for temperature and/or total pressure, based on measurements of these parameters at a remote location (or locations), provided that the following conditions are met:

(A) You must demonstrate that measurements at the remote location(s) can, when appropriate correction factors are applied, reliably and accurately represent the actual temperature or total pressure at the flow meter under all expected ambient conditions.

(B) You must make all temperature and/or total pressure measurements in the demonstration described in paragraph (i)(3)(ii)(A) of this section with calibrated gauges, sensors, transmitters, or other appropriate measurement devices. At a minimum, calibrate each of these devices to an accuracy within the appropriate error range for the specific measurement technology, according to one of the following. You may calibrate using a manufacturer's specification or an industry consensus standard.

(C) You must document the methods used for the demonstration described in paragraph (i)(3)(ii)(A) of this section in the written GHG Monitoring Plan under paragraph (g)(5)(i)(C) of this section. You must also include the data from the demonstration, the mathematical correlation(s) between the remote readings and actual flow meter conditions derived from the data, and any supporting engineering calculations in the GHG Monitoring Plan. You must maintain all of this information in a format suitable for auditing and inspection.

(D) You must use the mathematical correlation(s) derived from the demonstration described in paragraph (i)(3)(ii)(A) of this section to convert the remote temperature or the total pressure readings, or both, to the actual temperature or total pressure at the flow meter, or both, on a daily basis. You shall then use the actual temperature and total pressure values to correct the measured flow rates to standard conditions.

(E) You shall periodically check the correlation(s) between the remote and actual readings (at least once a year), and make any necessary adjustments to the mathematical relationship(s).

(4) Fuel billing meters are exempted from the calibration requirements of this section and from the GHG Monitoring Plan and recordkeeping provisions of paragraphs (g)(5)(i)(C), (g)(6), and (g)(7) of this section, provided that the fuel supplier and any unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company. Meters used exclusively to measure the flow rates of fuels that are used for unit startup are also exempted from the calibration requirements of this section.

(5) For a flow meter that has been previously calibrated in accordance with paragraph (i)(1) of this section, an additional calibration is not required by the date specified in paragraph (i)(1) of this section if, as of that date, the previous calibration is still active (*i.e.*, the device is not yet due for recalibration because the time interval between successive calibrations has not elapsed). In this case, the deadline for the successive calibrations of the flow meter shall be set according to one of the following. You may use either the manufacturer's recommended calibration schedule or you may use the industry consensus calibration schedule.

(6) For units and processes that operate continuously with infrequent outages, it may not be possible to meet the April 1, 2010 deadline for the initial calibration of a flow meter or other measurement device without disrupting normal process operation. In such cases, the owner or operator may postpone the initial calibration until the next scheduled maintenance outage. The best available information from company records may be used in the interim. The subsequent required recalibrations of the flow meters may be similarly postponed. Such postponements shall be documented in the monitoring plan that is required under paragraph (g)(5) of this section.

(7) If the results of an initial calibration or a recalibration fail to meet the required accuracy specification, data from the flow meter shall be considered invalid, beginning with the hour of the failed calibration and continuing until a successful calibration is completed. You shall follow the missing data provisions provided in the relevant missing data sections during the period of data invalidation.

(j) *Measurement device installation*—(1) *General.* If an owner or operator required to report under subpart P, subpart X or subpart Y of this part has process equipment or units that operate continuously and it is not possible to install a required flow meter or other measurement device by April 1, 2010, (or by any later date in 2010 approved by the Administrator as part of an extension of best available monitoring methods per paragraph (d) of this section) without process equipment or unit shutdown, or through a hot tap, the owner or operator may request an extension from the Administrator to delay installing the measurement device until the next scheduled process equipment or unit shutdown. If approval for such an extension is granted by the Administrator, the owner or operator must use best available monitoring methods during the extension period.

(2) *Requests for extension of the use of best available monitoring methods for measurement device installation.* The owner or operator must first provide the Administrator an initial notification of the intent to submit an extension request for use of best available monitoring methods beyond December 31, 2010 (or an earlier date approved by EPA) in cases where measurement device installation would require a process equipment or unit shutdown, or could only be done through a hot tap. The owner or operator must follow-up this initial notification with the complete extension request containing the information specified in paragraph (j)(4) of this section.

(3) *Timing of request.* (i) The initial notice of intent must be submitted no later than January 1, 2011, or by the end of the approved use of best available monitoring methods extension in 2010, whichever is earlier. The completed extension request must be submitted to the Administrator no later than February 15, 2011.

(ii) Any subsequent extensions to the original request must be submitted to the Administrator within 4 weeks of the owner or operator identifying the need to extend the request, but in any event no later than 4 weeks before the date for the planned process equipment or unit shutdown that was provided in the original or most recently approved request.

(4) *Content of the request.* Requests must contain the following information:

(i) Specific measurement device for which the request is being made and the location where each measurement device will be installed.

(ii) Identification of the specific rule requirements (by rule subpart, section, and paragraph numbers) requiring the measurement device.

(iii) A description of the reasons why the needed equipment could not be installed before April 1, 2010, or by the expiration date for the use of best available monitoring methods, in cases where an extension has been granted under § 98.3(d).

(iv) Supporting documentation showing that it is not practicable to isolate the process equipment or unit and install the measurement device without a full shutdown or a hot tap, and that there was no opportunity during 2010 to install the device. Include the date of the three most recent shutdowns for each relevant process equipment or unit, the frequency of shutdowns for each relevant process equipment or unit, and the date of the next planned process equipment or unit shutdown.

(v) Include a description of the proposed best available monitoring method for estimating GHG emissions during the time prior to installation of the meter.

(5) *Approval criteria.* The owner or operator must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to install the measurement device before April 1, 2010 (or by the expiration date for the use of best available monitoring methods, in cases where an extension has been granted under paragraph (d) of this section) without a process equipment or unit shutdown, or through a hot tap, and that the proposed method for estimating GHG emissions during the time before which the measurement device will be installed is appropriate. The Administrator will not initially approve the use of the proposed best available monitoring method past December 31, 2013.

(6) *Measurement device installation deadline.* Any owner or operator that submits both a timely initial notice of intent and a timely completed extension request under paragraph (j)(3) of this section to extend use of best available monitoring methods for measurement device installation must install all such devices by July 1, 2011 unless the extension request under this paragraph (j) is approved by the Administrator before July 1, 2011.

(7) *One time extension past December 31, 2013.* If an owner or operator determines that a scheduled process equipment or unit shutdown will not occur by December 31, 2013, the owner or operator may re-apply to use best available monitoring methods for one additional time period, not to extend beyond December 31, 2015. To extend use of best available monitoring methods past December 31, 2013, the owner or operator must submit a new extension request by June 1, 2013 that contains the information required in paragraph

(j)(4) of this section. The owner or operator must demonstrate to the Administrator's satisfaction that it continues to not be reasonably feasible to install the measurement device before December 31, 2013 without a process equipment or unit shutdown, or that installation of the measurement device could only be done through a hot tap, and that the proposed method for estimating GHG emissions during the time before which the measurement device will be installed is appropriate. An owner or operator that submits a request under this paragraph to extend use of best available monitoring methods for measurement device installation must install all such devices by December 31, 2013, unless the extension request under this paragraph is approved by the Administrator.

(k) *Revised global warming potentials and special provisions for reporting year 2013.* This paragraph (k) applies to owners or operators of facilities or suppliers that first become subject to any subpart of part 98 solely due to an amendment to Table A–1 of this subpart.

(1) A facility or supplier that was not subject to any subpart of part 98 for reporting year 2012, but first becomes subject to any subpart of part 98 due to a change in the GWP for one or more compounds in Table A–1 of this subpart, Global Warming Potentials, is not required to submit an annual GHG report for reporting year 2013.

(2) A facility or supplier that is subject to a subpart of part 98 for reporting year 2012, but first becomes subject to any subpart of part 98 due to a change in the GWP for one or more compounds in Table A–1 of this subpart, is not required to include those subparts for which the facility is subject only due to the change in the GWP in the annual GHG report submitted for reporting year 2013.

(3) Starting on January 1, 2014, facilities or suppliers identified in paragraphs (k)(1) or (2) of this section must start monitoring and collecting GHG data in compliance with the applicable subparts of part 98 for which the facility is subject due to the change in the GWP for the annual greenhouse gas report for reporting year 2014, which is due by March 31, 2015.

(l) *Special provision for best available monitoring methods in 2014.* This paragraph (l) applies to owners or operators of facilities or suppliers that first become subject to any subpart of part 98 due to an amendment to Table A–1 of this subpart, Global Warming Potentials.

(1) *Best available monitoring methods.* From January 1, 2014 to March 31, 2014, owners or operators subject to this paragraph (l) may use best available monitoring methods for any parameter (e.g., fuel use, feedstock rates) that cannot reasonably be measured according to the monitoring and QA/QC requirements of a relevant subpart. The owner or operator must use the calculation methodologies and equations in the ''Calculating GHG Emissions'' sections of each relevant subpart, but may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2014. Starting no later than April 1, 2014, the owner or operator must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraph (l)(2) of this section. Best available monitoring methods means any of the following methods:

(i) Monitoring methods currently used by the facility that do not meet the specifications of a relevant subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) *Requests for extension of the use of best available monitoring methods.* The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods beyond March 31, 2014.

(i) *Timing of request.* The extension request must be submitted to EPA no later than January 31, 2014.

(ii) *Content of request.* Requests must contain the following information:

(A) A list of specific items of monitoring instrumentation for which the request is being made and the locations where each piece of monitoring instrumentation will be installed.

(B) Identification of the specific rule requirements (by rule subpart, section, and paragraph numbers) for which the instrumentation is needed.

(C) A description of the reasons that the needed equipment could not be obtained and installed before April 1, 2014.

(D) If the reason for the extension is that the equipment cannot be purchased and delivered by April 1, 2014, supporting documentation such as the date the monitoring equipment was ordered, investigation of alternative suppliers and the dates by which alternative vendors promised delivery, backorder notices or unexpected delays, descriptions of actions taken to expedite delivery, and the current expected date of delivery.

(E) If the reason for the extension is that the equipment cannot be installed without a process unit shutdown, include supporting documentation demonstrating that it is not practicable to isolate the equipment and install the monitoring instrument without a full process unit shutdown. Include the date of the most recent process unit shutdown, the frequency of shutdowns for this process unit, and the date of the next planned shutdown during which the monitoring equipment can be installed. If there has been a shutdown or if there is a planned process unit shutdown between November 29, 2013 and April 1, 2014, include a justification of why the equipment could not be obtained and installed during that shutdown.

(F) A description of the specific actions the facility will take to obtain and install the equipment as soon as reasonably feasible and the expected date by which the equipment will be installed and operating.

(iii) Approval criteria. To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by April 1, 2014. The use of best available methods under this paragraph (l) will not be approved beyond December 31, 2014.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 39758, July 12, 2010; 75 FR 57685, Sept. 22, 2010; 75 FR 74816, Dec. 1, 2010; 75 FR 79134, Dec. 17, 2010; 75 FR 81344, Dec. 27, 2010; 76 FR 14818, Mar. 18, 2011; 76 FR 53065, Aug. 25, 2011; 76 FR 73899, Nov. 29, 2011; 77 FR 51488, Aug. 24, 2012; 78 FR 71946, Nov. 29, 2013]

§ 98.4 Authorization and responsibilities of the designated representative.

(a) *General.* Except as provided under paragraph (f) of this section, each facility, and each supplier, that is subject to this part, shall have one and only one designated representative, who shall be responsible for certifying, signing, and submitting GHG emissions reports and any other submissions for such facility and supplier respectively to the Administrator under this part. If the facility is required under any other part of title 40 of the Code of Federal Regulations to submit to the Administrator any other emission report that is subject to any requirement in 40 CFR part 75, the same individual shall be the designated representative responsible for certifying, signing, and submitting the GHG emissions reports and all such other emissions reports under this part.

(b) *Authorization of a designated representative.* The designated representative of the facility or supplier shall be an individual selected by an agreement binding on the owners and operators of such facility or supplier and shall act in accordance with the certification statement in paragraph (i)(4)(iv) of this section.

(c) *Responsibility of the designated representative.* Upon receipt by the Administrator of a complete certificate of representation under this section for a facility or supplier, the designated representative identified in such certificate of representation shall represent and, by his or her representations, actions, inactions, or submissions, legally bind each owner and operator of such facility or supplier in all matters pertaining to this part, notwithstanding any agreement between the designated representative and such owners and operators. The owners and operators shall be bound by any decision or order issued to the designated representative by the Administrator or a court.

(d) *Timing.* No GHG emissions report or other submissions under this part for a facility or supplier will be accepted until the Administrator has received a complete certificate of representation under this section for a designated representative of the facility or supplier. Such certificate of representation shall be submitted at least 60 days before the deadline for submission of the facility's or supplier's initial emission report under this part.

(e) *Certification of the GHG emissions report.* Each GHG emission report and any other submission under this part for a facility or supplier shall be certified, signed, and submitted by the designated representative or any alternate designated representative of the facility or supplier in accordance with this section and § 3.10 of this chapter.

(1) Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: ''I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.''

(2) The Administrator will accept a GHG emission report or other submission for a facility or supplier under this part only if the submission is certified, signed, and submitted in accordance with this section.

(f) *Alternate designated representative.* A certificate of representation under this section for a facility or supplier may designate one alternate designated representative, who shall be an individual selected by an agreement binding on the owners and operators, and may act on behalf of the designated representative, of such facility or supplier. The agreement by which the alternate designated representative is selected shall include a procedure for authorizing the alternate designated representative to act in lieu of the designated representative.

(1) Upon receipt by the Administrator of a complete certificate of representation under this section for a facility or supplier identifying an alternate designated representative.

(i) The alternate designated representative may act on behalf of the designated representative for such facility or supplier.

(ii) Any representation, action, inaction, or submission by the alternate designated representative shall be deemed to be a representation, action, inaction, or submission by the designated representative.

(2) Except in this section, whenever the term ''designated representative'' is used in this part, the term shall be construed to include the designated representative or any alternate designated representative.

(g) *Changing a designated representative or alternate designated representative.* The designated representative or alternate designated representative identified in a complete certificate of representation under this section for a facility or supplier received by the Administrator may be changed at any time upon receipt by the Administrator of another later signed, complete certificate of representation under this section for the facility or supplier. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous designated representative or the previous alternate designated representative of the facility or supplier before the time and date when the Administrator receives such later signed certificate of representation shall be binding on the new designated representative and the owners and operators of the facility or supplier.

(h) *Changes in owners and operators.* In the event an owner or operator of the facility or supplier is not included in the list of owners and operators in the certificate of representation under this section for the facility or supplier, such owner or operator shall be deemed to be subject to and bound by the certificate of representation, the representations, actions, inactions, and submissions of the designated representative and any alternate designated representative of the facility or supplier, as if the owner or operator were included in such list. Within 90 days after any change in the owners and operators of the facility or supplier (including the addition of a new owner or operator), the designated representative or any alternate designated representative shall submit a certificate of representation that is complete under this section except that such list shall be amended to reflect the change. If the designated representative or alternate designated representative determines at any time that an owner or operator of the facility or supplier is not included in such list and such exclusion is not the result of a change in the owners and operators, the designated representative or any alternate designated representative shall submit, within 90 days of making such determination, a certificate of representation that is complete under this section except that such list shall be amended to include such owner or operator.

(i) *Certificate of representation.* A certificate of representation shall be complete if it includes the following elements in a format prescribed by the Administrator in accordance with this section:

(1) Identification of the facility or supplier for which the certificate of representation is submitted.

(2) The name, organization name (company affiliation-employer), address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of the designated representative and any alternate designated representative.

(3) A list of the owners and operators of the facility or supplier identified in paragraph (i)(1) of this section, provided that, if the list includes the operators of the facility or supplier and the owners with control of the facility or supplier, the failure to include any other owners shall not make the certificate of representation incomplete.

(4) The following certification statements by the designated representative and any alternate designated representative:

(i) ''I certify that I was selected as the designated representative or alternate designated representative, as applicable, by an agreement binding on the owners and operators of the facility or supplier, as applicable.''

(ii) ''I certify that I have all the necessary authority to carry out my duties and responsibilities under 40 CFR part 98 on behalf of the owners and operators of the facility or supplier, as applicable, and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions.''

(iii) ''I certify that the owners and operators of the facility or supplier, as applicable, shall be bound by any order issued to me by the Administrator or a court regarding the facility or supplier.''

(iv) ''If there are multiple owners and operators of the facility or supplier, as applicable, I certify that I have given a written notice of my selection as the 'designated representative' or 'alternate designated representative', as applicable, and of the agreement by which I was selected to each owner and operator of the facility or supplier.''

(5) The signature of the designated representative and any alternate designated representative and the dates signed.

(j) *Documents of agreement.* Unless otherwise required by the Administrator, documents of agreement referred to in the certificate of representation shall not be submitted to the Administrator. The Administrator shall not be under any obligation to review or evaluate the sufficiency of such documents, if submitted.

(k) *Binding nature of the certificate of representation.* Once a complete certificate of representation under this section for a facility or supplier has been received, the Administrator will rely on the certificate of representation unless and until a later signed, complete certificate of representation under this section for the facility or supplier is received by the Administrator.

(l) *Objections concerning a designated representative.* (1) Except as provided in paragraph (g) of this section, no objection or other communication submitted to the Administrator concerning the authorization, or any representation, action, inaction, or submission, of the designated representative or alternate designated representative shall affect any representation, action, inaction, or submission of the designated representative or alternate designated representative, or the finality of any decision or order by the Administrator under this part.

(2) The Administrator will not adjudicate any private legal dispute concerning the authorization or any representation, action, inaction, or submission of any designated representative or alternate designated representative.

(m) *Delegation by designated representative and alternate designated representative.* (1) A designated representative or an alternate designated representative may delegate his or her own authority, to one or more individuals, to submit an electronic submission to the Administrator provided for or required under this part, except for a submission under this paragraph.

(2) In order to delegate his or her own authority, to one or more individuals, to submit an electronic submission to the Administrator in accordance with paragraph (m)(1) of this section, the designated representative or alternate designated representative must submit electronically to the Administrator a notice of delegation, in a format prescribed by the Administrator, that includes the following elements:

(i) The name, organization name (company affiliation-employer) address, e-mail address (if any), telephone number, and facsimile transmission number (if any) of such designated representative or alternate designated representative.

(ii) The name, address, e-mail address, telephone number, and facsimile transmission number (if any) of each such individual (referred to as an ''agent'').

(iii) For each such individual, a list of the type or types of electronic submissions under paragraph (m)(1) of this section for which authority is delegated to him or her.

(iv) For each type of electronic submission listed in accordance with paragraph (m)(2)(iii) of this section, the facility or supplier for which the electronic submission may be made.

(v) The following certification statements by such designated representative or alternate designated representative:

(A) ''I agree that any electronic submission to the Administrator that is by an agent identified in this notice of delegation and of a type listed, and for a facility or supplier designated, for such agent in this notice of delegation and that is made when I am a designated representative or alternate designated representative, as applicable, and before this notice of delegation is superseded by another notice of delegation under § 98.4(m)(3) shall be deemed to be an electronic submission certified, signed, and submitted by me.''

(B) ''Until this notice of delegation is superseded by a later signed notice of delegation under § 98.4(m)(3), I agree to maintain an e-mail account and to notify the Administrator immediately of any change in my e-mail address unless all delegation of authority by me under § 98.4(m) is terminated.''

(vi) The signature of such designated representative or alternate designated representative and the date signed.

(3) A notice of delegation submitted in accordance with paragraph (m)(2) of this section shall be effective, with regard to the designated representative or alternate designated representative identified in such notice, upon receipt of such notice by the Administrator and until receipt by the Administrator of another such notice that was signed later by such designated representative or alternate designated representative, as applicable. The later signed notice of delegation may replace any previously identified agent, add a new agent, or eliminate entirely any delegation of authority.

(4) Any electronic submission covered by the certification in paragraph (m)(2)(v)(A) of this section and made in accordance with a notice of delegation effective under paragraph (m)(3) of this

section shall be deemed to be an electronic submission certified, signed, and submitted by the designated representative or alternate designated representative submitting such notice of delegation.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79137, Dec. 17, 2010; 76 FR 73900, Nov. 29, 2011]

§98.5 How is the report submitted?

Each GHG report and certificate of representation for a facility or supplier must be submitted electronically in accordance with the requirements of §98.4 and in a format specified by the Administrator.

§98.6 Definitions.

All terms used in this part shall have the same meaning given in the Clean Air Act and in this section.

Absorbent circulation pump means a pump commonly powered by natural gas pressure that circulates the absorbent liquid between the absorbent regenerator and natural gas contactor.

Accuracy of a measurement at a specified level (e.g., one percent of full scale or one percent of the value measured) means that the mean of repeat measurements made by a device or technique are within 95 percent of the range bounded by the true value plus or minus the specified level.

Acid Rain Program means the program established under title IV of the Clean Air Act, and implemented under parts 72 through 78 of this chapter for the reduction of sulfur dioxide and nitrogen oxides emissions.

Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's authorized representative.

AGA means the American Gas Association

Agricultural by-products means those parts of arable crops that are not used for the primary purpose of producing food. Agricultural by-products include, but are not limited to, oat, corn and wheat straws, bagasse, peanut shells, rice and coconut husks, soybean hulls, palm kernel cake, cottonseed and sunflower seed cake, and pomace.

Air injected flare means a flare in which air is blown into the base of a flare stack to induce complete combustion of gas.

Alkali bypass means a duct between the feed end of the kiln and the preheater tower through which a portion of the kiln exit gas stream is withdrawn and quickly cooled by air or water to avoid excessive buildup of alkali, chloride and/or sulfur on the raw feed. This may also be referred to as the ''kiln exhaust gas bypass.''

Anaerobic digester means the system where wastes are collected and anaerobically digested in large containment vessels or covered lagoons. Anaerobic digesters stabilize waste by the microbial reduction of complex organic compounds to CO2 and CH4, which is captured and may be flared or used as fuel. Anaerobic digestion systems, include but are not limited to covered lagoon, complete mix, plug flow, and fixed film digesters.

Anaerobic lagoon, with respect to subpart JJ of this part, means a type of liquid storage system component that is designed and operated to stabilize wastes using anaerobic microbial processes. Anaerobic lagoons may be designed for combined stabilization and storage with varying lengths of retention time (up to a year or greater), depending on the climate region, volatile solids loading rate, and other operational factors.

Anode effect is a process upset condition of an aluminum electrolysis cell caused by too little alumina dissolved in the electrolyte. The anode effect begins when the voltage rises rapidly and exceeds a threshold voltage, typically 8 volts.

Anode Effect Minutes per Cell Day (24 hours) are the total minutes during which an electrolysis cell voltage is above the threshold voltage, typically 8 volts.

ANSI means the American National Standards Institute.

API means the American Petroleum Institute.

ASABE means the American Society of Agricultural and Biological Engineers.

ASME means the American Society of Mechanical Engineers.

ASTM means the American Society of Testing and Materials.

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

Aviation Gasoline means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in aviation reciprocating engines. Specifications can be found in ASTM Specification D910–07a, Standard Specification for Aviation Gasolines (incorporated by reference, see § 98.7).

B_0 means the maximum CH_4 producing capacity of a waste stream, kg CH_4/kg COD.

Basic oxygen furnace means any refractory-lined vessel in which high-purity oxygen is blown under pressure through a bath of molten iron, scrap metal, and fluxes to produce steel.

bbl means barrel.

Biodiesel means a mono-akyl ester derived from biomass and conforming to ASTM D6751–08, Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels.

Biogenic CO_2 means carbon dioxide emissions generated as the result of biomass combustion from combustion units for which emission calculations are required by an applicable part 98 subpart.

Biomass means non-fossilized and biodegradable organic material originating from plants, animals or microorganisms, including products, byproducts, residues and waste from agriculture, forestry and related industries as well as the non-fossilized and biodegradable organic fractions of industrial and municipal wastes, including gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.

Blast furnace means a furnace that is located at an integrated iron and steel plant and is used for the production of molten iron from iron ore pellets and other iron bearing materials.

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

Blendstocks—Others are products used for blending or compounding into finished motor gasoline that are not defined elsewhere. Excludes Gasoline Treated as Blendstock (GTAB), Diesel Treated as Blendstock (DTAB), conventional blendstock for oxygenate blending (CBOB), reformulated blendstock for oxygenate blending (RBOB), oxygenates (e.g. fuel ethanol and methyl tertiary butyl ether), butane, and pentanes plus.

Blowdown mean the act of emptying or depressuring a vessel. This may also refer to the discarded material such as blowdown water from a boiler or cooling tower.

Blowdown vent stack emissions mean natural gas and/or CO_2 released due to maintenance and/or blowdown operations including compressor blowdown and emergency shut-down (ESD) system testing.

British Thermal Unit or Btu means the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at about 39.2 degrees Fahrenheit.

Bulk, with respect to industrial GHG suppliers and CO2 suppliers, means the transfer of a product inside containers, including but not limited to tanks, cylinders, drums, and pressure vessels.

Bulk natural gas liquid or NGL refers to mixtures of hydrocarbons that have been separated from natural gas as liquids through the process of absorption, condensation, adsorption, or other methods. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus. Bulk NGL is sold to fractionators or to refineries and petrochemical plants where the fractionation takes place.

Butane, or n-Butane, is a paraffinic straight-chain hydrocarbon with molecular formula C_4H_{10}.

Butylene, or n-Butylene, is an olefinic straight-chain hydrocarbon with molecular formula C_4H_8.

By-product coke oven battery means a group of ovens connected by common walls, where coal undergoes destructive distillation under positive pressure to produce coke and coke oven gas from which by-products are recovered.

Calcination means the process of thermally treating minerals to decompose carbonates from ore.

Calculation methodology means a methodology prescribed under the section "Calculating GHG Emissions" in any subpart of part 98.

Calibrated bag means a flexible, non-elastic, anti-static bag of a calibrated volume that can be affixed to an emitting source such that the emissions inflate the bag to its calibrated volume.

Carbon dioxide equivalent or CO_2e means the number of metric tons of CO_2 emissions with the same global warming potential as one metric ton of another greenhouse gas, and is calculated using Equation A–1 of this subpart.

Carbon dioxide production well means any hole drilled in the earth for the primary purpose of extracting carbon dioxide from a geologic formation or group of formations which contain deposits of carbon dioxide.

Carbon dioxide production well facility means one or more carbon dioxide production wells that are located on one or more contiguous or adjacent properties, which are under the control of the same entity. Carbon dioxide production wells located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line, or pipeline, shall be considered part of the same CO_2 production well facility if they otherwise meet the definition.

Carbon dioxide stream means carbon dioxide that has been captured from an emission source (e.g. a power plant or other industrial facility) or extracted from a carbon dioxide production well plus incidental associated substances either derived from the source materials and the capture process or extracted with the carbon dioxide.

Carbon share means the percent of total mass that carbon represents in any product.

Carbonate means compounds containing the radical $CO_3^{-2.}$ Upon calcination, the carbonate radical decomposes to evolve carbon dioxide (CO_2). Common carbonates consumed in the mineral industry include calcium carbonate ($CaCO_3$) or calcite; magnesium carbonate ($MgCO_3$) or magnesite; and calcium-magnesium carbonate ($CaMg(CO_3)_2$) or dolomite.

Carbonate-based mineral means any of the following minerals used in the manufacture of glass: Calcium carbonate ($CaCO_3$), calcium magnesium carbonate ($CaMg(CO_3)_2$), sodium carbonate (Na_2CO_3), barium carbonate ($BaCO_3$), potassium carbonate (K_2CO_3), lithium carbonate (Li_2CO_3), and strontium carbonate ($SrCO_3$).

Carbonate-based mineral mass fraction means the following: For limestone, the mass fraction of calcium carbonate ($CaCO_3$) in the limestone; for dolomite, the mass fraction of calcium magnesium carbonate ($CaMg(CO_3)_2$) in the dolomite; for soda ash, the mass fraction of sodium carbonate (Na_2CO_3) in the soda ash; for barium carbonate, the mass fraction of barium carbonate ($BaCO_3$) in the barium carbonate; for potassium carbonate, the mass fraction of potassium carbonate (K_2CO_3) in the potassium carbonate; for lithium carbonate, the mass fraction of lithium carbonate (Li_2CO_3); and for strontium carbonate, the mass fraction of strontium carbonate ($SrCO_3$).

Carbonate-based raw material means any of the following materials used in the manufacture of glass: Limestone, dolomite, soda ash, barium carbonate, potassium carbonate, lithium carbonate, and strontium carbonate.

Catalytic cracking unit means a refinery process unit in which petroleum derivatives are continuously charged and hydrocarbon molecules in the presence of a catalyst are fractured into smaller molecules, or react with a contact material suspended in a fluidized bed to improve feedstock quality for additional processing and the catalyst or contact material is continuously regenerated by burning off coke and other deposits. Catalytic cracking units include both fluidized bed systems, which are referred to as fluid catalytic cracking units (FCCU), and moving bed systems, which are also referred to as thermal catalytic cracking units. The unit includes the riser, reactor, regenerator, air blowers, spent catalyst or contact material stripper, catalyst or contact material recovery equipment, and regenerator equipment for controlling air pollutant emissions and for heat recovery.

CBOB-Summer (conventional blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Conventional-Summer.

CBOB-Winter (conventional blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Conventional-Winter.

Cement kiln dust means non-calcined to fully calcined dust produced in the kiln or pyroprocessing line. Cement kiln dust is a fine-grained, solid, highly alkaline material removed from the cement kiln exhaust gas by scrubbers (filtration baghouses and/or electrostatic precipitators).

Centrifugal compressor means any equipment that increases the pressure of a process natural gas or CO_2 by centrifugal action, employing rotating movement of the driven shaft.

Centrifugal compressor dry seal emissions mean natural gas or CO_2 released from a dry seal vent pipe and/or the seal face around the rotating shaft where it exits one or both ends of the compressor case.

Centrifugal compressor dry seals mean a series of rings around the compressor shaft where it exits the compressor case that operates mechanically under the opposing forces to prevent natural gas or CO_2 from escaping to the atmosphere.

Centrifugal compressor wet seal degassing vent emissions means emissions that occur when the high-pressure oil barriers for centrifugal compressors are depressurized to release absorbed natural gas or CO_2. High-pressure oil is used as a barrier against escaping gas in centrifugal compressor shafts. Very little gas escapes through the oil barrier, but under high pressure, considerably more gas is absorbed by the oil. The seal oil is purged of the absorbed gas (using heaters, flash tanks, and degassing techniques) and recirculated. The separated gas is commonly vented to the atmosphere.

Certified standards means calibration gases certified by the manufacturer of the calibration gases to be accurate to within 2 percent of the value on the label or calibration gases.

CH_4 means methane.

Chemical recovery combustion unit means a combustion device, such as a recovery furnace or fluidized-bed reactor where spent pulping liquor from sulfite or semi-chemical pulping processes is burned to recover pulping chemicals.

Chemical recovery furnace means an enclosed combustion device where concentrated spent liquor produced by the kraft or soda pulping process is burned to recover pulping chemicals and produce steam. Includes any recovery furnace that burns spent pulping liquor produced from both the kraft and soda pulping processes.

Chloride process means a production process where titanium dioxide is produced using calcined petroleum coke and chlorine as raw materials.

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

CO_2 means carbon dioxide.

Coal means all solid fuels classified as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials Designation ASTM D388–05 Standard Classification of Coals by Rank (incorporated by reference, *see* §98.7).

COD means the chemical oxygen demand as determined using methods specified pursuant to 40 CFR part 136.

Cogeneration unit means a unit that produces electrical energy and useful thermal energy for industrial, commercial, or heating or cooling purposes, through the sequential or simultaneous use of the original fuel energy.

Coke burn-off means the coke removed from the surface of a catalyst by combustion during catalyst regeneration. Coke burn-off also means the coke combusted in fluid coking unit burner.

Cokemaking means the production of coke from coal in either a by-product coke oven battery or a non-recovery coke oven battery.

Commercial applications means executing a commercial transaction subject to a contract. A commercial application includes transferring custody of a product from one facility to another if it otherwise meets the definition.

Company records means, in reference to the amount of fuel consumed by a stationary combustion unit (or by a group of such units), a complete record of the methods used, the measurements made, and the calculations performed to quantify fuel usage. Company records may include, but are not limited to, direct measurements of fuel consumption by gravimetric or volumetric means, tank drop measurements, and calculated values of fuel usage obtained by measuring auxiliary parameters such as steam generation or unit operating hours. Fuel billing records obtained from the fuel supplier qualify as company records.

Connector means to flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, ''T's'' or valves) or a pipe line and a piece of equipment or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this part.

Container glass means glass made of soda-lime recipe, clear or colored, which is pressed and/or blown into bottles, jars, ampoules, and other products listed in North American Industry Classification System 327213 (NAICS 327213).

Continuous bleed means a continuous flow of pneumatic supply natural gas to the process control device (*e.g.* level control, temperature control, pressure control) where the supply gas pressure is modulated by the process condition, and then flows to the valve controller where the signal is compared with the process set-point to adjust gas pressure in the valve actuator.

Continuous emission monitoring system or CEMS means the total equipment required to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes, a permanent record of gas concentrations, pollutant emission rates, or gas volumetric flow rates from stationary sources.

Continuous glass melting furnace means a glass melting furnace that operates continuously except during periods of maintenance, malfunction, control device installation, reconstruction, or rebuilding.

Conventional-Summer refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR 80.40, but which meet summer RVP standards required under 40 CFR 80.27 or as specified by the state. NOTE: This category excludes conventional gasoline for oxygenate blending (CBOB) as well as other blendstock.

Conventional-Winter refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which do not meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR 80.40 or the summer RVP standards required under 40 CFR 80.27 or as specified by the state. NOTE: This category excludes conventional blendstock for oxygenate blending (CBOB) as well as other blendstock.

Crude oil means a mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities. (1) Depending upon the characteristics of the crude stream, it may also include any of the following:

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

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

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

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

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

Daily spread means a manure management system component in which manure is routinely removed from a confinement facility and is applied to cropland or pasture within 24 hours of excretion.

Day means any consistently designated 24 hour period during which an emission unit is operated.

Decarburization vessel means any vessel used to further refine molten steel with the primary intent of reducing the carbon content of the steel, including but not limited to vessels used for argon-oxygen decarburization and vacuum oxygen decarburization.

Deep bedding systems for cattle swine means a manure management system in which, as manure accumulates, bedding is continually added to absorb moisture over a production cycle and possibly for as long as 6 to 12 months. This manure management system also is known as a bedded pack manure management system and may be combined with a dry lot or pasture.

Degasification system means the entirety of the equipment that is used to drain gas from underground coal mines. This includes all degasification wells and gob gas vent holes at the underground coal mine. Degasification systems include gob and premine surface drainage wells, gob and premine in-mine drainage wells, and in-mine gob and premine cross-measure borehole wells.

Degradable organic carbon (DOC) means the fraction of the total mass of a waste material that can be biologically degraded.

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

Dehydrator vent emissions means natural gas and CO_2 released from a natural gas dehydrator system absorbent (typically glycol) reboiler or regenerator to the atmosphere or a flare, including stripping natural gas and motive natural gas used in absorbent circulation pumps.

Delayed coking unit means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is produced in a series of closed, batch system reactors. A *delayed coking unit* consists of the coke drums and ancillary equipment associated with a single fractionator.

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

Density means the mass contained in a given unit volume (mass/volume).

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

Destruction means:

(1) With respect to landfills and manure management, the combustion of methane in any on-site or off-site combustion technology. Destroyed methane includes, but is not limited to, methane combusted by flaring, methane destroyed by thermal oxidation, methane combusted for use in on-site energy or heat production technologies, methane that is conveyed through pipelines (including natural gas pipelines) for off-site combustion, and methane that is collected for any other on-site or off-site use as a fuel.

(2) With respect to fluorinated GHGs, the expiration of a fluorinated GHG to the destruction efficiency actually achieved. Such destruction does not result in a commercially useful end product.

Destruction device, for the purposes of subparts II and TT of this part, means a flare, thermal oxidizer, boiler, turbine, internal combustion engine, or any other combustion unit used to destroy or oxidize methane contained in landfill gas or wastewater biogas.

Destruction efficiency means the efficiency with which a destruction device reduces the mass of a greenhouse gas fed into the device. Destruction efficiency, or flaring destruction efficiency, refers to the fraction of the gas that leaves the flare partially or fully oxidized. The destruction efficiency is expressed in Equation A–2 of this section:

$$DE = 1 - \frac{tGHG_{iOUT}}{tGHG_{iIN}} \quad \text{(Eq. A-2)}$$

where:

DE = Destruction Efficiency

$tGHG_{iIN}$ = The mass of GHG i fed into the destruction device

$tGHG_{iOUT}$ = The mass of GHG i exhausted from the destruction device

Diesel—Other is any distillate fuel oil not defined elsewhere, including Diesel Treated as Blendstock (DTAB).

DIPE (diisopropyl ether, $(CH_3)_2CHOCH(CH_3)_2$) is an ether as described in ‘‘Oxygenates.’’

Direct liquefaction means the conversion of coal directly into liquids, rather than passing through an intermediate gaseous state.

Direct reduction furnace means a high temperature furnace typically fired with natural gas to produce solid iron from iron ore or iron ore pellets and coke, coal, or other carbonaceous materials.

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

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

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

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

DOC_f means the fraction of DOC that actually decomposes under the (presumably anaerobic) conditions within the landfill.

Dry lot means a manure management system component consisting of a paved or unpaved open confinement area without any significant vegetative cover where accumulating manure may be removed periodically.

Electric arc furnace (EAF) means a furnace that produces molten alloy metal and heats the charge materials with electric arcs from carbon electrodes.

Electric arc furnace steelmaking means the production of carbon, alloy, or specialty steels using an EAF. This definition excludes EAFs at steel foundries and EAFs used to produce nonferrous metals.

Electrothermic furnace means a furnace that heats the charged materials with electric arcs from carbon electrodes.

Emergency generator means a stationary combustion device, such as a reciprocating internal combustion engine or turbine that serves solely as a secondary source of mechanical or electrical power whenever the primary energy supply is disrupted or discontinued during power outages or natural disasters that are beyond the control of the owner or operator of a facility. An emergency generator operates only during emergency situations, for training of personnel under simulated emergency conditions, as part of emergency demand response procedures, or for standard performance testing procedures as required by law or by the generator manufacturer. A generator that serves as a back-up power source under conditions of load shedding, peak shaving, power interruptions pursuant to an interruptible power service agreement, or scheduled facility maintenance shall not be considered an emergency generator.

Emergency equipment means any auxiliary fossil fuel-powered equipment, such as a fire pump, that is used only in emergency situations.

ETBE (ethyl tertiary butyl ether, $(CH_3)_3COC_2H$) is an ether as described in ''Oxygenates.''

Ethane is a paraffinic hydrocarbon with molecular formula C_2H_6.

Ethanol is an anhydrous alcohol with molecular formula C_2H_5OH.

Ethylene is an olefinic hydrocarbon with molecular formula C_2H_4.

Ex refinery gate means the point at which a petroleum product leaves the refinery.

Experimental furnace means a glass melting furnace with the sole purpose of operating to evaluate glass melting processes, technologies, or glass products. An experimental furnace does not produce glass that is sold (except for further research and development purposes) or that is used as a raw material for non-experimental furnaces.

Export means to transport a product from inside the United States to persons outside the United States, excluding any such transport on behalf of the United States military including foreign military sales under the Arms Export Control Act.

Exporter means any person, company or organization of record that transfers for sale or for other benefit, domestic products from the United States to another country or to an affiliate in another country, excluding any such transfers on behalf of the United States military or military purposes including foreign military sales under the Arms Export Control Act. An exporter is not the entity merely transporting the domestic products, rather an exporter is the entity deriving the principal benefit from the transaction.

Facility means any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas. Operators of military installations may classify such installations as more than a single facility based on distinct and independent functional groupings within contiguous military properties.

Feed means the prepared and mixed materials, which include but are not limited to materials such as limestone, clay, shale, sand, iron ore, mill scale, cement kiln dust and flyash, that are fed to the kiln. Feed does not include the fuels used in the kiln to produce heat to form the clinker product.

Feedstock means raw material inputs to a process that are transformed by reaction, oxidation, or other chemical or physical methods into products and by-products. Supplemental fuel burned to provide heat or thermal energy is not a feedstock.

Fischer-Tropsch process means a catalyzed chemical reaction in which synthesis gas, a mixture of carbon monoxide and hydrogen, is converted into liquid hydrocarbons of various forms.

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

Flat glass means glass made of soda-lime recipe and produced into continuous flat sheets and other products listed in NAICS 327211.

Flowmeter means a device that measures the mass or volumetric rate of flow of a gas, liquid, or solid moving through an open or closed conduit (e.g. flowmeters include, but are not limited to, rotameters, turbine meters, coriolis meters, orifice meters, ultra-sonic flowmeters, and vortex flowmeters).

Fluid coking unit means one or more refinery process units in which high molecular weight petroleum derivatives are thermally cracked and petroleum coke is continuously produced in a fluidized bed system. The fluid coking unit includes equipment for controlling air pollutant emissions and for heat recovery on the fluid coking burner exhaust vent. There are two basic types of fluid coking units: A traditional fluid coking unit in which only a small portion of the coke produced in the unit is burned to fuel the unit and the fluid coking burner exhaust vent is directed to the atmosphere (after processing in a CO boiler or other air pollutant control equipment) and a flexicoking unit in which an auxiliary burner is used to partially combust a significant portion of the produced petroleum coke to generate a low value fuel gas that is used as fuel in other combustion sources at the refinery.

Fluorinated greenhouse gas means sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3), and any fluorocarbon except for controlled substances as defined at 40 CFR part 82, subpart A and substances with vapor pressures of less than 1 mm of Hg absolute at 25 degrees C. With these exceptions, ''fluorinated GHG'' includes but is not limited to any hydrofluorocarbon, any perfluorocarbon, any fully fluorinated linear, branched or cyclic alkane, ether, tertiary amine or aminoether, any perfluoropolyether, and any hydrofluoropolyether.

Fossil fuel means natural gas, petroleum, coal, or any form of solid, liquid, or gaseous fuel derived from such material, for purpose of creating useful heat.

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

Fuel means solid, liquid or gaseous combustible material.

Fuel gas means gas generated at a petroleum refinery or petrochemical plant and that is combusted separately or in any combination with any type of gas.

Fuel gas system means a system of compressors, piping, knock-out pots, mix drums, and, if necessary, units used to remove sulfur contaminants from the fuel gas (e.g., amine scrubbers) that collects fuel gas from one or more sources for treatment, as necessary, and transport to a stationary combustion unit. A fuel gas system may have an overpressure vent to a flare but the primary purpose for a fuel gas system is to provide fuel to the various combustion units at the refinery or petrochemical plant.

Furnace slag means a by-product formed in metal melting furnaces when slagging agents, reducing agents, and/or fluxes (*e.g.*, coke ash, limestone, silicates) are added to remove impurities from the molten metal.

Gas collection system or landfill gas collection system means a system of pipes used to collect landfill gas from different locations in the landfill by means of a fan or similar mechanical draft equipment to a single location for treatment (thermal destruction) or use. Landfill gas collection systems may also include knock-out or separator drums and/or a compressor. A single landfill may have multiple gas collection systems. Landfill gas collection systems do not include ''passive'' systems, whereby landfill gas flows naturally to the surface of the landfill where an opening or pipe (vent) is installed to allow for natural gas flow.

Gas conditions mean the actual temperature, volume, and pressure of a gas sample.

Gas-fired unit means a stationary combustion unit that derives more than 50 percent of its annual heat input from the combustion of gaseous fuels, and the remainder of its annual heat input from the combustion of fuel oil or other liquid fuels.

Gas monitor means an instrument that continuously measures the concentration of a particular gaseous species in the effluent of a stationary source.

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

Gaseous fuel means a material that is in the gaseous state at standard atmospheric temperature and pressure conditions and that is combusted to produce heat and/or energy.

Gasification means the conversion of a solid or liquid raw material into a gas.

Gasoline—Other is any gasoline that is not defined elsewhere, including GTAB (gasoline treated as blendstock).

Glass melting furnace means a unit comprising a refractory-lined vessel in which raw materials are charged and melted at high temperature to produce molten glass.

Glass produced means the weight of glass exiting a glass melting furnace.

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

GPA means the Gas Processors Association.

Greenhouse gas or GHG means carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF6), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and other fluorinated greenhouse gases as defined in this section.

GTBA (gasoline-grade tertiary butyl alcohol, $(CH_3)_3COH$), or t-butanol, is an alcohol as described in ''Oxygenates.''

Heavy Gas Oils are petroleum distillates with an approximate boiling range from 651 °F to 1,000 °F.

Heel means the amount of gas that remains in a shipping container after it is discharged or off-loaded (that is no more than ten percent of the volume of the container).

High-bleed pneumatic devices are automated, continuous bleed flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate in excess of 6 standard cubic feet per hour.

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

Hydrofluorocarbons or HFCs means a class of GHGs consisting of hydrogen, fluorine, and carbon.

Import means, to land on, bring into, or introduce into, any place subject to the jurisdiction of the United States whether or not such landing, bringing, or introduction constitutes an importation within the meaning of the customs laws of the United States, with the following exemptions:

(1) Off-loading used or excess fluorinated GHGs or nitrous oxide of U.S. origin from a ship during servicing.

(2) Bringing fluorinated GHGs or nitrous oxide into the U.S. from Mexico where the fluorinated GHGs or nitrous

oxide had been admitted into Mexico in bond and were of U.S. origin.

(3) Bringing fluorinated GHGs or nitrous oxide into the U.S. when transported in a consignment of personal or household effects or in a similar noncommercial situation normally exempted from U.S. Customs attention.

(4) Bringing fluorinated GHGs or nitrous into U.S. jurisdiction exclusively for U. S. military purposes.

Importer means any person, company, or organization of record that for any reason brings a product into the United States from a foreign country, excluding introduction into U.S. jurisdiction exclusively for United States military purposes. An importer is the person, company, or organization primarily liable for the payment of any duties on the merchandise or an authorized agent acting on their behalf. The term includes, as appropriate:

(1) The consignee.

(2) The importer of record.

(3) The actual owner.

(4) The transferee, if the right to draw merchandise in a bonded warehouse has been transferred.

Indurating furnace means a furnace where unfired taconite pellets, called green balls, are hardened at high temperatures to produce fired pellets for use in a blast furnace. Types of indurating furnaces include straight gate and grate kiln furnaces.

Industrial greenhouse gases means nitrous oxide or any fluorinated greenhouse gas.

In-line kiln/raw mill means a system in a portland cement production process where a dry kiln system is integrated with the raw mill so that all or a portion of the kiln exhaust gases are used to perform the drying operation of the raw mill, with no auxiliary heat source used. In this system the kiln is capable of operating without the raw mill operating, but the raw mill cannot operate without the kiln gases, and consequently, the raw mill does not generate a separate exhaust gas stream.

Intermittent bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for automatically maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. These are snap-acting or throttling devices that discharge all or a portion of the full volume of the actuator intermittently when control action is necessary, but does not bleed continuously.

Isobutane is a paraffinic branch chain hydrocarbon with molecular formula $C_4H_{10.}$

Isobutylene is an olefinic branch chain hydrocarbon with molecular formula $C_4H_{8.}$

Kerosene is a light petroleum distillate with a maximum distillation temperature of 400 °F at the 10-percent recovery point, a final maximum boiling point of 572 °F, a minimum flash point of 100 °F, and a maximum freezing point of -22 °F. Included are No. 1–K and No. 2–K, distinguished by maximum sulfur content (0.04 and 0.30 percent of total mass, respectively), as well as all other grades of kerosene called range or stove oil. Excluded is kerosene-type jet fuel (see definition herein).

Kerosene-type jet fuel means a kerosene-based product used in commercial and military turbojet and turboprop aircraft. The product has a maximum distillation temperature of 400 °F at the 10 percent recovery point and a final maximum boiling point of 572 °F. Included are Jet A, Jet A–1, JP–5, and JP–8.

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

Landfill means an area of land or an excavation in which wastes are placed for permanent disposal and that is not a land application unit, surface impoundment, injection well, or waste pile as those terms are defined under 40 CFR 257.2.

Landfill gas means gas produced as a result of anaerobic decomposition of waste materials in the landfill. Landfill gas generally contains 40 to 60 percent methane on a dry basis, typically less than 1 percent non-methane organic chemicals, and the remainder being carbon dioxide.

Liberated means released from coal and surrounding rock strata during the mining process. This includes both methane emitted from the ventilation system and methane drained from degasification systems.

Lime is the generic term for a variety of chemical compounds that are produced by the calcination of limestone or dolomite. These products include but are not limited to calcium oxide, high-calcium quicklime, calcium hydroxide, hydrated lime, dolomitic quicklime, and dolomitic hydrate.

Liquid/Slurry means a manure management component in which manure is stored as excreted or with some minimal addition of water to facilitate handling and is stored in either tanks or earthen ponds, usually for periods less than one year.

Low-bleed pneumatic devices mean automated flow control devices powered by pressurized natural gas and used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature. Part of the gas power stream that is regulated by the process condition flows to a valve actuator controller where it vents continuously (bleeds) to the atmosphere at a rate equal to or less than six standard cubic feet per hour.

Lubricants include all grades of lubricating oils, from spindle oil to cylinder oil to those used in greases. Petroleum lubricants may be produced from distillates or residues.

Makeup chemicals means carbonate chemicals (e.g., sodium and calcium carbonates) that are added to the chemical recovery areas of chemical pulp mills to replace chemicals lost in the process.

Manure composting means the biological oxidation of a solid waste including manure usually with bedding or another organic carbon source typically at thermophilic temperatures produced by microbial heat production. There are four types of composting employed for manure management: Static, in vessel, intensive windrow and passive windrow. Static composting typically occurs in an enclosed channel, with forced aeration and continuous mixing. In vessel composting occurs in piles with forced aeration but no mixing. Intensive windrow composting occurs in windrows with regular turning for mixing and aeration. Passive windrow composting occurs in windrows with infrequent turning for mixing and aeration.

Maximum rated heat input capacity means the hourly heat input to a unit (in mmBtu/hr), when it combusts the maximum amount of fuel per hour that it is capable of combusting on a steady state basis, as of the initial installation of the unit, as specified by the manufacturer.

Maximum rated input capacity means the maximum charging rate of a municipal waste combustor unit expressed in tons per day of municipal solid waste combusted, calculated according to the procedures under 40 CFR 60.58b(j).

Mcf means thousand cubic feet.

Methane conversion factor means the extent to which the CH_4 producing capacity (B_o) is realized in each type of treatment and discharge pathway and system. Thus, it is an indication of the degree to which the system is anaerobic.

Methane correction factor means an adjustment factor applied to the methane generation rate to account for portions of the landfill that remain aerobic. The methane correction factor can be considered the fraction of the total landfill waste volume that is ultimately disposed of in an anaerobic state. Managed landfills that have soil or other cover materials have a methane correction factor of 1.

Methanol (CH_3OH) is an alcohol as described in ''Oxygenates.''

Midgrade gasoline has an octane rating greater than or equal to 88 and less than or equal to 90. This definition applies to the midgrade categories of Conventional-Summer, Conventional-Winter, Reformulated-Summer, and Reformulated-Winter. For midgrade categories of RBOB-Summer, RBOB-Winter, CBOB-Summer, and CBOB-Winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

Miscellaneous products include all refined petroleum products not defined elsewhere. It includes, but is not limited to, naphtha-type jet fuel (Jet B and JP–4), petrolatum lube refining byproducts (aromatic extracts and tars), absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, waste feedstocks, and specialty oils. It excludes organic waste sludges, tank bottoms, spent catalysts, and sulfuric acid.

MMBtu means million British thermal units.

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

Mscf means thousand standard cubic feet.

MTBE (methyl tertiary butyl ether, $(CH_3)_3COCH_3$) is an ether as described in ''Oxygenates.''

Municipal solid waste landfill or MSW landfill means an entire disposal facility in a contiguous geographical space where household waste is placed in or on land. An MSW landfill may also receive other types of RCRA Subtitle D wastes (40 CFR 257.2) such as commercial solid waste, nonhazardous sludge, conditionally exempt small quantity generator waste, and industrial solid waste. Portions of an MSW landfill may be separated by access roads, public roadways, or other public right-of-ways. An MSW landfill may be publicly or privately owned.

Municipal solid waste or MSW means solid phase household, commercial/retail, and/or institutional waste. Household waste includes material discarded by single and multiple residential dwellings, hotels, motels, and other similar permanent or temporary housing establishments or facilities. Commercial/retail waste includes material discarded by stores, offices, restaurants, warehouses, non-manufacturing activities at industrial facilities, and other similar establishments or facilities. Institutional waste includes material discarded by schools, nonmedical waste discarded by hospitals, material discarded by non-manufacturing activities at prisons and government facilities, and material discarded by other similar establishments or facilities. Household, commercial/retail, and institutional wastes include yard waste, refuse-derived fuel, and motor vehicle maintenance materials. Insofar as there is separate collection, processing and disposal of industrial source waste streams consisting of used oil, wood pallets, construction, renovation, and demolition wastes (which includes, but is not limited to, railroad ties and telephone poles), paper, clean wood, plastics, industrial process or manufacturing wastes, medical waste, motor vehicle parts or vehicle fluff, or used tires that do not contain hazardous waste identified or listed under 42 U.S.C. § 6921, such wastes are not municipal solid waste. However, such wastes qualify as municipal solid waste where they are collected with other municipal solid waste or are otherwise combined with other municipal solid waste for processing and/or disposal.

Municipal wastewater treatment plant means a series of treatment processes used to remove contaminants and pollutants from domestic, business, and industrial wastewater collected in city sewers and transported to a centralized wastewater treatment system such as a publicly owned treatment works (POTW).

N_2O means nitrous oxide.

Naphthas (<401 °F) is a generic term applied to a petroleum fraction with an approximate boiling range between 122 °F and 400 °F. The naphtha fraction of crude oil is the raw material for gasoline and is composed largely of paraffinic hydrocarbons.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane. Natural gas may be field quality or pipeline quality.

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

Natural gas liquids (NGLs) means those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, or other methods. Generally, such liquids consist of ethane, propane, butanes, and pentanes plus. Bulk NGLs refers to mixtures of NGLs that are sold or delivered as undifferentiated product from natural gas processing plants.

Natural gasoline means a mixture of liquid hydrocarbons (mostly pentanes and heavier hydrocarbons) extracted from natural gas. It includes isopentane.

NIST means the United States National Institute of Standards and Technology.

Nitric acid production line means a series of reactors and absorbers used to produce nitric acid.

Nitrogen excreted is the nitrogen that is excreted by livestock in manure and urine.

Non-crude feedstocks means any petroleum product or natural gas liquid that enters the refinery to be further refined or otherwise used on site.

Non-recovery coke oven battery means a group of ovens connected by common walls and operated as a unit, where coal undergoes destructive distillation under negative pressure to produce coke, and which is designed for the combustion of the coke oven gas from which by-products are not recovered.

North American Industry Classification System (NAICS) code(s) means the six-digit code(s) that represents the product(s)/activity(s)/service(s) at a facility or supplier as listed in the FEDERAL REGISTER and defined in ''North American Industrial Classification System Manual 2007,'' available from the U.S. Department of Commerce, National Technical Information Service, Alexandria, VA 22312, phone (703) 605–6000 or (800) 553–6847. *http://www.census.gov/eos/www/naics/.*

Oil-fired unit means a stationary combustion unit that derives more than 50 percent of its annual heat input from the combustion of fuel oil, and the remainder of its annual heat input from the combustion of natural gas or other gaseous fuels.

Open-ended valve or lines (OELs) means any valve, except pressure relief valves, having one side of the valve seat in contact with process fluid and one side open to atmosphere, either directly or through open piping.

Operating hours means the duration of time in which a process or process unit is utilized; this excludes shutdown, maintenance, and standby.

Operational change means, for purposes of § 98.3(b), a change in the type of feedstock or fuel used, a change in operating hours, or a change in process production rate.

Operator means any person who operates or supervises a facility or supplier.

Other oils (>401 °F) are oils with a boiling range equal to or greater than 401 °F that are generally intended for use as a petrochemical feedstock and are not defined elsewhere.

Outer Continental Shelf means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in 43 U.S.C. 1331, and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

Owner means any person who has legal or equitable title to, has a leasehold interest in, or control of a facility or supplier, except a person whose legal or equitable title to or leasehold interest in the facility or supplier arises solely because the person is a limited partner in a partnership that has legal or equitable title to, has a leasehold interest in, or control of the facility or supplier shall not be considered an ''owner'' of the facility or supplier.

Oxygenates means substances which, when added to gasoline, increase the oxygen content of the gasoline. Common oxygenates are ethanol, methyl tertiary butyl ether (MTBE), ethyl tertiary butyl ether (ETBE), tertiary amyl methyl ether (TAME), diisopropyl ether (DIPE), and methanol.

Pasture/Range/Paddock means the manure from pasture and range grazing animals is allowed to lie as deposited, and is not managed.

Pentanes plus, or C5+, is a mixture of hydrocarbons that is a liquid at ambient temperature and pressure, and consists mostly of pentanes (five carbon chain) and higher carbon number hydrocarbons. Pentanes plus includes, but is not limited to, normal pentane, isopentane, hexanes-plus (natural gasoline), and plant condensate.

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

Petrochemical means methanol, acrylonitrile, ethylene, ethylene oxide, ethylene dichloride, and any form of carbon black.

Petrochemical feedstocks means feedstocks derived from petroleum for the manufacture of chemicals, synthetic rubber, and a variety of plastics. This category is usually divided into naphthas less than 401 °F and other oils greater than 401 °F.

Petroleum means oil removed from the earth and the oil derived from tar sands and shale.

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

Petroleum product means all refined and semi-refined products that are produced at a refinery by processing crude oil and other petroleum-based feedstocks, including petroleum products derived from co-processing biomass and petroleum feedstock together, but not including plastics or plastic products. Petroleum products may be combusted for energy use, or they may be used either for non-energy processes or as non-energy products. The definition of petroleum product for importers and exporters excludes waxes.

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

Pit storage below animal confinement (deep pits) means the collection and storage of manure typically below a slatted floor in an enclosed animal confinement facility. This usually occurs with little or no added water for periods less than one year.

Plant code means either of the following:

(1) The Plant ID code assigned by the Department of Energy's Energy Information Administration. The Energy Information Administration Plant ID code is also referred to as the "ORIS code", "ORISPL code", "Facility ID", or "Facility code", among other names.

(2) If a Plant ID code has not been assigned by the Department of Energy's Energy Information Administration, then plant code means a code beginning with "88" assigned by the EPA's Clean Air Markets Division for electronic reporting.

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

(1) The equipment is attached to a foundation.

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

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

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

Poultry manure with litter means a manure management system component that is similar to cattle and swine deep bedding except usually not combined with a dry lot or pasture. The system is typically used for poultry breeder flocks and for the production of meat type chickens (broiler) and other fowl.

Poultry manure without litter means a manure management system component that may manage manure in a liquid form, similar to open pits in enclosed animal confinement facilities. These systems may alternatively be designed and operated to dry manure as it accumulates. The latter is known as a high-rise manure management system and is a form of passive windrow manure composting when designed and operated properly.

Precision of a measurement at a specified level (e.g., one percent of full scale or one percent of the value measured) means that 95 percent of repeat measurements made by a device or technique are within the range bounded by the mean of the measurements plus or minus the specified level.

Premium grade gasoline is gasoline having an antiknock index, i.e., octane rating, greater than 90. This definition applies to the premium grade categories of Conventional-Summer, Conventional-Winter, Reformulated-Summer, and Reformulated-Winter. For premium grade categories of RBOB-Summer, RBOB-Winter, CBOB-Summer, and CBOB-Winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

Pressed and blown glass means glass which is pressed, blown, or both, into products such as light bulbs, glass fiber, technical glass, and other products listed in NAICS 327212.

Pressure relief device or pressure relief valve or pressure safety valve means a safety device used to prevent operating pressures from exceeding the maximum allowable working pressure of the process equipment. A common pressure relief device is but not limited to a spring-loaded pressure relief valve. Devices that are actuated either by a pressure of less than or equal to 2.5 psig or by a vacuum are not pressure relief devices.

Primary fuel means the fuel that provides the greatest percentage of the annual heat input to a stationary fuel combustion unit.

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

Process unit means the equipment assembled and connected by pipes and ducts to process raw materials and to manufacture either a final product or an intermediate used in the onsite production of other products. The process unit also includes the purification of recovered byproducts.

Process vent means means a gas stream that: Is discharged through a conveyance to the atmosphere either directly or after passing through a control device; originates from a unit operation, including but not limited to reactors (including reformers, crackers, and furnaces, and separation equipment for products and recovered byproducts); and contains or has the potential to contain GHG that is generated in the process. Process vent does not include safety device discharges, equipment leaks, gas streams routed to a fuel gas system or to a flare, discharges from storage tanks.

Propane is a paraffinic hydrocarbon with molecular formula $C_3H_{8.}$

Propylene is an olefinic hydrocarbon with molecular formula $C_3H_{6.}$

Pulp mill lime kiln means the combustion units (e.g., rotary lime kiln or fluidized bed calciner) used at a kraft or soda pulp mill to calcine lime mud, which consists primarily of calcium carbonate, into quicklime, which is calcium oxide.

Pushing means the process of removing the coke from the coke oven at the end of the coking cycle. Pushing begins when coke first begins to fall from the oven into the quench car and ends when the quench car enters the quench tower.

Raw mill means a ball and tube mill, vertical roller mill or other size reduction equipment, that is not part of an in-line kiln/raw mill, used to grind feed to the appropriate size. Moisture may be added or removed from the feed during the grinding operation. If the raw mill is used to remove moisture from feed materials, it is also, by definition, a raw material dryer. The raw mill also includes the air separator associated with the raw mill.

RBOB-Summer (reformulated blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Reformulated-Summer.

RBOB-Winter (reformulated blendstock for oxygenate blending) means a petroleum product which, when blended with a specified type and percentage of oxygenate, meets the definition of Reformulated-Winter.

Reciprocating compressor means a piece of equipment that increases the pressure of a process natural gas or CO_2 by positive displacement, employing linear movement of a shaft driving a piston in a cylinder.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas or CO_2 that escapes to the atmosphere.

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

Reformulated-Summer refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR 80.40 and 40 CFR 80.41, and summer RVP standards required under 40 CFR 80.27 or as specified by the state. Reformulated gasoline excludes Reformulated Blendstock for Oxygenate Blending (RBOB) as well as other blendstock.

Reformulated-Winter refers to finished gasoline formulated for use in motor vehicles, the composition and properties of which meet the requirements of the reformulated gasoline regulations promulgated by the U.S. Environmental Protection Agency under 40 CFR 80.40 and 40 CFR 80.41, but which do not meet summer RVP standards required under 40 CFR 80.27 or as specified by the state. NOTE: This category includes Oxygenated Fuels Program Reformulated Gasoline (OPRG). Reformulated gasoline excludes Reformulated Blendstock for Oxygenate Blending (RBOB) as well as other blendstock.

Regular grade gasoline is gasoline having an antiknock index, i.e., octane rating, greater than or equal to 85 and less than 88. This definition applies to the regular grade categories of Conventional-Summer, Conventional-Winter, Reformulated-Summer, and Reformulated-Winter. For regular grade categories of RBOB-Summer, RBOB-Winter, CBOB-Summer, and CBOB-Winter, this definition refers to the expected octane rating of the finished gasoline after oxygenate has been added to the RBOB or CBOB.

Rendered animal fat, or tallow, means fats extracted from animals which are generally used as a feedstock in making biodiesel.

Research and development means those activities conducted in process units or at laboratory bench-scale settings whose purpose is to conduct research and development for new processes, technologies, or products and whose purpose is not for the manufacture of products for commercial sale, except in a *de minimis* manner.

Residual Fuel Oil No. 5 (Navy Special) is a classification for the heavier fuel oil generally used in steam powered vessels in government service and inshore power plants. It has a minimum flash point of 131 °F.

Residual Fuel Oil No. 6 (a.k.a. Bunker C) is a classification for the heavier fuel oil generally used for the production of electric power, space heating, vessel bunkering and various industrial purposes. It has a minimum flash point of 140 °F.

Residuum is residue from crude oil after distilling off all but the heaviest components, with a boiling range greater than 1,000 °F.

Road oil is any heavy petroleum oil, including residual asphaltic oil used as a dust palliative and surface treatment on roads and highways. It is generally produced in six grades, from 0, the most liquid, to 5, the most viscous.

Rotary lime kiln means a unit with an inclined rotating drum that is used to produce a lime product from limestone by calcination.

Safety device means a closure device such as a pressure relief valve, frangible disc, fusible plug, or any other type of device which functions exclusively to prevent physical damage or permanent deformation to a unit or its air emission control equipment by venting gases or vapors directly to the atmosphere during unsafe conditions resulting from an unplanned, accidental, or emergency event. A safety device is not used for routine venting of gases or vapors from the vapor headspace underneath a cover such as during filling of the unit or to adjust the pressure in response to normal daily diurnal ambient temperature fluctuations. A safety device is designed to remain in a closed position during normal operations and open only when the internal pressure, or another relevant parameter, exceeds the device threshold setting applicable to the air emission control equipment as determined by the owner or operator based on manufacturer recommendations, applicable regulations, fire protection and prevention codes and practices, or other requirements for the safe handling of flammable, combustible, explosive, reactive, or hazardous materials.

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

Semi-refined petroleum product means all oils requiring further processing. Included in this category are unfinished oils which are produced by the partial refining of crude oil and include the following: Naphthas and lighter oils; kerosene and light gas oils; heavy gas oils; and residuum, and all products that require further processing or the addition of blendstocks.

Sendout means, in the context of a local distribution company, the total deliveries of natural gas to customers over a specified time interval (typically hour, day, month, or year). Sendout is the sum of gas received through the city gate, gas withdrawn from on-system storage or peak shaving plants, and gas produced and delivered into the distribution system; and is net of any natural gas injected into on-system storage. It comprises gas sales, exchange, deliveries, gas used by company, and unaccounted for gas. Sendout is measured at the city gate station, and other on-system receipt points from storage, peak shaving, and production.

Sensor means a device that measures a physical quantity/quality or the change in a physical quantity/quality, such as temperature, pressure, flow rate, pH, or liquid level.

SF_6 means sulfur hexafluoride.

Shutdown means the cessation of operation of an emission source for any purpose.

Silicon carbide means an artificial abrasive produced from silica sand or quartz and petroleum coke.

Sinter process means a process that produces a fused aggregate of fine iron-bearing materials suited for use in a blast furnace. The sinter machine is composed of a continuous traveling grate that conveys a bed of ore fines and other finely divided iron-bearing material and fuel (typically coke breeze), a burner at the feed end of the grate for ignition, and a series of downdraft windboxes along the length of the strand to support downdraft combustion and heat sufficient to produce a fused sinter product.

Site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically located.

Smelting furnace means a furnace in which lead-bearing materials, carbon-containing reducing agents, and fluxes are melted together to form a molten mass of material containing lead and slag.

Solid by-products means plant matter such as vegetable waste, animal materials/wastes, and other solid biomass, except for wood, wood waste, and sulphite lyes (black liquor).

Solid storage is the storage of manure, typically for a period of several months, in unconfined piles or stacks. Manure is able to be stacked due to the presence of a sufficient amount of bedding material or loss of moisture by evaporation.

Sour gas means any gas that contains significant concentrations of hydrogen sulfide. Sour gas may include untreated fuel gas, amine stripper off-gas, or sour water stripper gas.

Sour natural gas means natural gas that contains significant concentrations of hydrogen sulfide (H_2S)and/or carbon dioxide (CO_2) that exceed the concentrations specified for commercially saleable natural gas delivered from transmission and distribution pipelines.

Special naphthas means all finished products with the naphtha boiling range (290 ° to 470 °F) that are generally used as paint thinners, cleaners or solvents. These products are refined to a specified flash point. Special naphthas include all commercial hexane and cleaning solvents conforming to ASTM Specification D1836–07, Standard Specification for Commercial Hexanes, and D235–02 (Reapproved 2007), Standard Specification for Mineral Spirits (Petroleum Spirits) (Hydrocarbon Dry Cleaning Solvent), respectively. Naphthas to be blended or marketed as motor gasoline or aviation gasoline, or that are to be used as petrochemical and synthetic natural gas (SNG) feedstocks are excluded.

Spent liquor solids means the dry weight of the solids in the spent pulping liquor that enters the chemical recovery furnace or chemical recovery combustion unit.

Spent pulping liquor means the residual liquid collected from on-site pulping operations at chemical pulp facilities that is subsequently fired in chemical recovery furnaces at kraft and soda pulp facilities or chemical recovery combustion units at sulfite or semi-chemical pulp facilities.

Standard conditions or standard temperature and pressure (STP), for the purposes of this part, means either 60 or 68 degrees Fahrenheit and 14.7 pounds per square inch absolute.

Steam reforming means a catalytic process that involves a reaction between natural gas or other light hydrocarbons and steam. The result is a mixture of hydrogen, carbon monoxide, carbon dioxide, and water.

Still gas means any form or mixture of gases produced in refineries by distillation, cracking, reforming, and other processes. The principal constituents are methane, ethane, ethylene, normal butane, butylene, propane, and propylene.

Storage tank means a vessel (excluding sumps) that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of non-earthen materials (e.g., wood, concrete, steel, plastic) that provide structural support.

Sulfur recovery plant means all process units which recover sulfur or produce sulfuric acid from hydrogen sulfide (H_2S) and/or sulfur dioxide (SO_2) from a common source of sour gas at a petroleum refinery. The sulfur recovery plant also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels or loading facilities downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits, and, if present, oxidation or reduction control systems, or incinerator, thermal oxidizer, or similar combustion device. Multiple sulfur recovery units are a single sulfur recovery plant only when the units share the same source of sour gas. Sulfur recovery units that receive source gas from completely segregated sour gas treatment systems are separate sulfur recovery plants.

Supplemental fuel means a fuel burned within a petrochemical process that is not produced within the process itself.

Supplier means a producer, importer, or exporter in any supply category included in Table A–5 to this subpart, as defined by the corresponding subpart of this part.

Sweet gas is natural gas with low concentrations of hydrogen sulfide (H_2S) and/or carbon dioxide (CO_2) that does not require (or has already had) acid gas treatment to meet pipeline corrosion-prevention specifications for transmission and distribution.

Taconite iron ore processing means an industrial process that separates and concentrates iron ore from taconite, a low grade iron ore, and heats the taconite in an indurating furnace to produce taconite pellets that are used as the primary feed material for the production of iron in blast furnaces at integrated iron and steel plants.

TAME means tertiary amyl methyl ether, $(CH_3)_2(C_2H_5)COCH_3$).

Trace concentrations means concentrations of less than 0.1 percent by mass of the process stream.

Transform means to use and entirely consume (except for trace concentrations) nitrous oxide or fluorinated GHGs in the manufacturing of other chemicals for commercial purposes.

Transformation does not include burning of nitrous oxide.

Transshipment means the continuous shipment of nitrous oxide or a fluorinated GHG from a foreign state of origin through the United States or its territories to a second foreign state of final destination, as long as the shipment does not enter into United States jurisdiction. A transshipment, as it moves through the United States or its territories, cannot be re-packaged, sorted or otherwise changed in condition.

Trona means the raw material (mineral) used to manufacture soda ash; hydrated sodium bicarbonate carbonate (e.g., $Na2CO_3.NaHCO_3.2H_2O$).

Ultimate analysis means the determination of the percentages of carbon, hydrogen, nitrogen, sulfur, and chlorine and (by difference) oxygen in the gaseous products and ash after the complete combustion of a sample of an organic material.

Unfinished oils are all oils requiring further processing, except those requiring only mechanical blending.

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

United States parent company(s) means the highest-level United States company(s) with an ownership interest in the facility or supplier as of December 31 of the year for which data are being reported.

Unstabilized crude oil means, for the purposes of this part, crude oil that is pumped from the well to a pipeline or pressurized storage vessel for transport to the refinery without intermediate storage in a storage tank at atmospheric pressures. Unstabilized crude oil is characterized by having a true vapor pressure of 5 pounds per square inch absolute (psia) or greater.

Used oil means a petroleum-derived or synthetically-derived oil whose physical properties have changed as a result of handling or use, such that the oil cannot be used for its original purpose. Used oil consists primarily of automotive oils (*e.g.*, used motor oil, transmission oil, hydraulic fluids, brake fluid, *etc.*) and industrial oils (*e.g.*, industrial engine oils, metalworking oils, process oils, industrial grease, *etc*).

Valve means any device for halting or regulating the flow of a liquid or gas through a passage, pipeline, inlet, outlet, or orifice; including, but not limited to, gate, globe, plug, ball, butterfly and needle valves.

Vapor recovery system means any equipment located at the source of potential gas emissions to the atmosphere or to a flare, that is composed of piping, connections, and, if necessary, flow-inducing devices, and that is used for routing the gas back into the process as a product and/or fuel.

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

Vegetable oil means oils extracted from vegetation that are generally used as a feedstock in making biodiesel.

Ventilation hole or shaft means a vent hole or shaft employed at an underground coal mine to serve as the outlet or conduit to move air from the ventilation system out of the mine.

Ventilation system means a system that is used to control the concentration of methane and other gases within mine working areas through mine ventilation, rather than a mine degasification system. A ventilation system consists of fans that move air through the mine workings to dilute methane concentrations.

Volatile solids are the organic material in livestock manure and consist of both biodegradable and non-biodegradable fractions.

Waelz kiln means an inclined rotary kiln in which zinc-containing materials are charged together with a carbon reducing agent (e.g., petroleum coke, metallurgical coke, or anthracite coal).

Waxes means a solid or semi-solid material at 77 °F consisting of a mixture of hydrocarbons obtained or derived from petroleum fractions, or through a Fischer-Tropsch type process, in which the straight chained paraffin series predominates. This includes all marketable wax, whether crude or refined, with a congealing point between 80 (or 85) and 240 °F and a maximum oil content of 50 weight percent.

Well completions means the process that allows for the flow of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and test the reservoir flow characteristics, steps which may vent produced gas to the atmosphere via an open pit or tank. Well completion also involves connecting the well bore to the reservoir, which may include treating the formation or installing tubing, packer(s), or lifting equipment, steps that do not significantly vent natural gas to the atmosphere. This process may also include high-rate flowback of injected gas, water, oil, and proppant used to fracture or re-fracture and prop open new fractures in existing lower permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Well workover means the process(es) of performing one or more of a variety of remedial operations on producing petroleum and natural gas wells to try to increase production. This process also includes high-rate flowback of injected gas, water, oil, and proppant used to re-fracture and prop-open new fractures in existing low permeability gas reservoirs, steps that may vent large quantities of produced gas to the atmosphere.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. Wellhead equipment includes all equipment, permanent and portable, located on the improved land area (*i.e.* well pad) surrounding one or multiple wellheads.

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

Wood residuals means materials recovered from three principal sources: Municipal solid waste (MSW); construction and demolition debris; and primary timber processing. Wood residuals recovered from MSW include wooden furniture, cabinets, pallets and containers, scrap lumber (from sources other than construction and demolition activities), and urban tree and landscape residues. Wood residuals from construction and demolition debris originate from the construction, repair, remodeling and demolition of houses and non-residential structures. Wood residuals from primary timber processing include bark, sawmill slabs and edgings, sawdust, and peeler log cores. Other sources of wood residuals include, but are not limited to, railroad ties, telephone and utility poles, pier and dock timbers, wastewater process sludge from paper mills, trim, sander dust, and sawdust from wood products manufacturing (including resinated wood product residuals), and logging residues.

Wool fiberglass means fibrous glass of random texture, including fiberglass insulation, and other products listed in NAICS 327993.

Working capacity, for the purposes of subpart TT of this part, means the maximum volume or mass of waste that is actually placed in the landfill from an individual or representative type of container (such as a tank, truck, or roll-off bin) used to convey wastes to the landfill, taking into account that the container may not be able to be 100 percent filled and/or 100 percent emptied for each load.

You means an owner or operator subject to Part 98.

Zinc smelters means a facility engaged in the production of zinc metal, zinc oxide, or zinc alloy products from zinc sulfide ore concentrates, zinc calcine, or zinc-bearing scrap and recycled materials through the use of pyrometallurgical techniques involving the reduction and volatization of zinc-bearing feed materials charged to a furnace.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 39759, July 12, 2010; 75 FR 57686, Sept. 22, 2010; 75 FR 66457, Oct. 28, 2010; 75 FR 74487, Nov. 30, 2010; 75 FR 74816, Dec. 1, 2010; 75 FR 79137, Dec. 17, 2010; 76 FR 73900, Nov. 29, 2011; 76 FR 80573, Dec. 23, 2011; 78 FR 71948, Nov. 29, 2013]

§ 98.7 What standardized methods are incorporated by reference into this part?

The materials listed in this section are incorporated by reference in the corresponding sections noted. These incorporations by reference were approved by the Director of Federal Register in accordance with 5 U.S.C. 552(a) and 1 CFR part 51. These materials are incorporated as they exist on the date of approval, and a notice of any change in the materials will be published in the FEDERAL REGISTER. The materials are available for purchase at the corresponding address in this section. The materials are available for inspection at the EPA Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC, phone (202) 566–1744 and at the National Archives and Records Administration (NARA). For information on the availability of this material at NARA, call 202–741–6030, or go to: *http://www.archives.gov/federal__register/code__of__federal__regulations/ibr__locations.html.*

(a)–(b) [Reserved]

(c) The following material is available for purchase from the ASM International, 9639 Kinsman Road, Materials Park, OH 44073, (440) 338–5151, *http://www.asminternational.org.*

(1) ASM CS–104 UNS No. G10460—Alloy Digest April 1985 (Carbon Steel of Medium Carbon Content), incorporation by reference (IBR) approved for § 98.174(b).

(2) [Reserved]

(d) The following material is available for purchase from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, *http://www.asme.org.*

(1) ASME MFC–3M–2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, incorporation by reference (IBR) approved for § 98.124(m)(1), § 98.324(e), § 98.354(d), § 98.354(h), § 98.344(c) and § 98.364(e).

(2) ASME MFC–4M–1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters, IBR approved for § 98.124(m)(2), § 98.324(e), § 98.344(c), § 98.354(h), and § 98.364(e).

(3) ASME MFC–5M–1985 (Reaffirmed 1994) Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flow Meters, IBR approved for § 98.124(m)(3) and § 98.354(d).

(4) ASME MFC–6M–1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters, IBR approved for § 98.124(m)(4), § 98.324(e), § 98.344(c), § 98.354(h), and § 98.364(e).

(5) ASME MFC–7M–1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles, IBR approved for § 98.124(m)(5), § 98.324(e), § 98.344(c), § 98.354(h), and § 98.364(e).

(6) ASME MFC–9M–1988 (Reaffirmed 2001) Measurement of Liquid Flow in Closed Conduits by Weighing Method, IBR approved for § 98.124(m)(6).

(7) ASME MFC–11M–2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for § 98.124(m)(7), § 98.324(e), § 98.344(c), and § 98.354(h).

(8) ASME MFC–14M–2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters, IBR approved for § 98.124(m)(8), § 98.324(e), § 98.344(c), § 98.354(h), and § 98.364(e).

(9) ASME MFC–16–2007 Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flow Meters, IBR approved for § 98.354(d).

(10) ASME MFC–18M–2001 Measurement of Fluid Flow Using Variable Area Meters, IBR approved for § 98.324(e), § 98.344(c), § 98.354(h), and § 98.364(e).

(e) The following material is available for purchase from the American Society for Testing and Material (ASTM), 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, *http://www.astm.org.*

(1) ASTM C25–06 Standard Test Method for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime, incorporation by reference (IBR) approved

for § 98.114(b), § 98.174(b), § 98.184(b), § 98.194(c), and § 98.334(b).

(2) ASTM C114–09 Standard Test Methods for Chemical Analysis of Hydraulic Cement, IBR approved for § 98.84(a), § 98.84(b), and § 98.84(c).

(3) ASTM D235–02 (Reapproved 2007) Standard Specification for Mineral Spirits (Petroleum Spirits) (Hydrocarbon Dry Cleaning Solvent), IBR approved for § 98.6.

(4) ASTM D240–02 (Reapproved 2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter, IBR approved for § 98.254(e).

(5) ASTM D388–05 Standard Classification of Coals by Rank, IBR approved for § 98.6.

(6) ASTM D910–07a Standard Specification for Aviation Gasolines, IBR approved for § 98.6.

(7) [Reserved]

(8) ASTM D1826–94 (Reapproved 2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimeter, IBR approved for § 98.254(e).

(9) ASTM D1836–07 Standard Specification for Commercial Hexanes, IBR approved for § 98.6.

(10) ASTM D1945–03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 98.74(c), § 98.164(b), § 98.244(b), § 98.254(d), § 98.324(d), § 98.354(g), and § 98.344(b).

(11) ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography, IBR approved for § 98.74(c), § 98.164(b), § 98.254(d), § 98.324(d), § 98.344(b), § 98.354(g), and § 98.364(c).

(12) ASTM D2013–07 Standard Practice for Preparing Coal Samples for Analysis, IBR approved for § 98.164(b).

(13) ASTM D2234/D2234M–07 Standard Practice for Collection of a Gross Sample of Coal, IBR approved for § 98.164(b).

(14) ASTM D2502–04 Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils From Viscosity Measurements, IBR approved for § 98.74(c).

(15) ASTM D2503–92 (Reapproved 2007) Standard Test Method for Relative Molecular Mass (Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure, IBR approved for § 98.74(c) and § 98.254(d)(6).

(16) ASTM D2505–88 (Reapproved 2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography, IBR approved for § 98.244(b).

(17) ASTM D2597–94 (Reapproved 2004) Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography, IBR approved for § 98.164(b).

(18) ASTM D3176–89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke, IBR approved for § 98.74(c), § 98.164(b), § 98.244(b), § 98.254(i), § 98.284(c), § 98.284(d), § 98.314(c), § 98.314(d), and § 98.314(f).

(19) ASTM D3238–95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method, IBR approved for § 98.74(c) and § 98.164(b).

(20) ASTM D3588–98 (Reapproved 2003) Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, IBR approved for § 98.254(e).

(21) ASTM D3682–01 (Reapproved 2006) Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes, IBR approved for § 98.144(b).

(22) ASTM D4057–06 Standard Practice for Manual Sampling of Petroleum and Petroleum Products, IBR approved for § 98.164(b).

(23) ASTM D4177–95 (Reapproved 2005) Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, IBR approved for § 98.164(b).

(24) ASTM D4809–06 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimeter (Precision Method), IBR approved for § 98.254(e).

(25) ASTM D4891–89 (Reapproved 2006) Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, IBR approved for § 98.254(e) and § 98.324(d).

(26) ASTM D5291–02 (Reapproved 2007) Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants, IBR approved

for §98.74(c), §98.164(b), §98.244(b), and §98.254(i).

(27) ASTM D5373–08 Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal, IBR approved for §98.74(c), §98.114(b), §98.164(b), §98.174(b), §98.184(b), §98.244(b), §98.254(i), §98.274(b), §98.284(c), §98.284(d), §98.314(c), §98.314(d), §98.314(f), and §98.334(b).

(28) [Reserved]

(29) ASTM D6060–96 (Reapproved 2001) Standard Practice for Sampling of Process Vents With a Portable Gas Chromatograph, IBR approved for §98.244(b).

(30) ASTM D6348–03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy, IBR approved for §98.54(b), Table I–9 to subpart I of this part, §98.224(b), and §98.414(n).

(31) ASTM D6609–08 Standard Guide for Part-Stream Sampling of Coal, IBR approved for §98.164(b).

(32) ASTM D6751–08 Standard Specification for Biodiesel Fuel Blend Stock (B100) for Middle Distillate Fuels, IBR approved for §98.6.

(33) ASTM D6866–08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis, IBR approved for §98.34(d), §98.34(e), and §98.36(e).

(34) ASTM D6883–04 Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles, IBR approved for §98.164(b).

(35) ASTM D7430–08ae1 Standard Practice for Mechanical Sampling of Coal, IBR approved for §98.164(b).

(36) ASTM D7459–08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources, IBR approved for §98.34(d), §98.34(e), and §98.36(e).

(37) ASTM E359–00 (Reapproved 2005)e1 Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate), IBR approved for §98.294(a) and §98.294(b).

(38) ASTM E1019–08 Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques, IBR approved for §98.174(b).

(39) [Reserved]

(40) ASTM E1915–07a Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry, IBR approved for §98.174(b).

(41) ASTM E1941–04 Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys, IBR approved for §98.114(b), §98.184(b), §98.334(b).

(42) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography, IBR approved for §98.164(b), §98.244(b), §98.254(d), §98.324(d), §98.344(b), and §98.354(g).

(43) ASTM D1941–91 (Reapproved 2007) Standard Test Method for Open Channel Flow Measurement of Water with the Parshall Flume, approved June 15, 2007, IBR approved for §98.354(d).

(44) ASTM D5614–94 (Reapproved 2008) Standard Test Method for Open Channel Flow Measurement of Water with Broad-Crested Weirs, approved October 1, 2008, IBR approved for §98.354(d).

(45) ASTM D6349–09 Standard Test Method for Determination of Major and Minor Elements in Coal, Coke, and Solid Residues from Combustion of Coal and Coke by Inductively Coupled Plasma—Atomic Emission Spectrometry, IBR approved for §98.144(b).

(46) ASTM D2879–97 (Reapproved 2007) Standard Test Method for Vapor Pressure-Temperature Relationship and Initial Decomposition Temperature of Liquids by Isoteniscope (ASTM D2879), approved May 1, 2007, IBR approved for §98.128.

(47) ASTM D7359–08 Standard Test Method for Total Fluorine, Chlorine and Sulfur in Aromatic Hydrocarbons and Their Mixtures by Oxidative Pyrohydrolytic Combustion followed by Ion Chromatography Detection (Combustion Ion Chromatography-CIC) (ASTM D7359), approved October 15, 2008, IBR approved for §98.124(e)(2).

(48) ASTM D2593–93 (Reapproved 2009) Standard Test Method for Butadiene Purity and Hydrocarbon Impurities by Gas Chromatography, approved July 1, 2009, IBR approved for §98.244(b)(4)(xi).

(49) ASTM D7633–10 Standard Test Method for Carbon Black—Carbon Content, approved May 15, 2010, IBR approved for § 98.244(b)(4)(xii).

(f) The following material is available for purchase from the Gas Processors Association (GPA), 6526 East 60th Street, Tulsa, Oklahoma 74143, (918) 493–3872, *http://www.gasprocessors.com.*

(1) [Reserved]

(2) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, IBR approved for § 98.164(b), § 98.254(d), § 98.344(b), and § 98.354(g).

(g) The following material is available for purchase from the International Standards Organization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm.*

(1) ISO 3170: Petroleum liquids—Manual sampling—Third Edition 2004–02–01, IBR approved for § 98.164(b).

(2) ISO 3171: Petroleum Liquids—Automatic pipeline sampling—Second Edition 1988–12–01, IBR approved for § 98.164(b).

(3) [Reserved]

(4) ISO/TR 15349–1: 1998, Unalloyed steel—Determination of low carbon content. Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation) (1998–10–15)—First Edition, IBR approved for § 98.174(b).

(5) ISO/TR 15349–3: 1998, Unalloyed steel—Determination of low carbon content. Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating) (1998–10–15)—First Edition, IBR approved for § 98.174(b).

(h) The following material is available for purchase from the National Lime Association (NLA), 200 North Glebe Road, Suite 800, Arlington, Virginia 22203, (703) 243–5463, *http://www.lime.org.*

(1) CO_2 Emissions Calculation Protocol for the Lime Industry—English Units Version, February 5, 2008 Revision—National Lime Association, incorporation by reference (IBR) approved for § 98.194(c) and § 98.194(e).

(2) [Reserved]

(i) The following material is available for purchase from the National Institute of Standards and Technology (NIST), 100 Bureau Drive, Stop 1070, Gaithersburg, MD 20899–1070, (800) 877–8339, *http://www.nist.gov/index.html.*

(1) Specifications, Tolerances, and Other Technical Requirements For Weighing and Measuring Devices, NIST Handbook 44 (2009), incorporation by reference (IBR) approved for § 98.244(b), § 98.254(h), and § 98.344(a).

(2) [Reserved]

(j) The following material is available for purchase from the Technical Association of the Pulp and Paper Industry (TAPPI), 15 Technology Parkway South, Norcross, GA 30092, (800) 332–8686, *http://www.tappi.org.*

(1) T650 om-05 Solids Content of Black Liquor, TAPPI, incorporation by reference (IBR) approved for § 98.276(c) and § 98.277(d).

(2) T684 om-06 Gross Heating Value of Black Liquor, TAPPI, incorporation by reference (IBR) approved for § 98.274(b).

(k) The following material is available for purchase from Standard Methods, at *http://www.standardmethods.org*, (877) 574–1233; or, through a joint publication agreement from the American Public Health Association (APHA), P.O. Box 933019, Atlanta, GA 31193–3019, (888) 320–APHA (2742), *http://www.apha.org/publications/pubscontact/.*

(1) Method 2540G Total, Fixed, and Volatile Solids in Solid and Semisolid Samples, IBR approved for § 98.464(b).

(2) [Reserved]

(l) The following material is available from the U.S. Department of Labor, Mine Safety and Health Administration, 1100 Wilson Boulevard, 21st Floor, Arlington, VA 22209–3939, (202) 693–9400, *http://www.msha.gov.*

(1) General Coal Mine Inspection Procedures and Inspection Tracking System, Handbook Number: PH–08–V–1, January 1, 2008, IBR approved for § 98.324(b).

(2) [Reserved]

(m) The following material is available from the U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, (202) 272–0167, *http://www.epa.gov.*

(1) NPDES Compliance Inspection Manual, Chapter 5, Sampling, EPA 305–X–04–001, July 2004, *http://www.epa.gov/*

compliance/monitoring/programs/cwa/npdes.html, IBR approved for §98.354(c).

(2) U.S. EPA NPDES Permit Writers' Manual, Section 7.1.3, Sample Collection Methods, EPA 833–B–96–003, December 1996, *http://www.epa.gov/npdes/pubs/owm0243.pdf*, IBR approved for §98.354(c).

(3) Protocol for Measuring Destruction or Removal Efficiency (DRE) of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing, Version 1, EPA–430–R–10–003, March 2010 (EPA 430–R–10–003), *http://www.epa.gov/semiconductor-pfc/documents/dre_protocol.pdf*, IBR approved for §98.94(f)(4)(i), §98.94(g)(3), §98.97(d)(4), §98.98, Appendix A to subpart I of this part, §98.124(e)(2), and §98.414(n)(1).

(4) Emissions Inventory Improvement Program, Volume II: Chapter 16, Methods for Estimating Air Emissions from Chemical Manufacturing Facilities, August 2007, Final, *http://www.epa.gov/ttnchie1/eiip/techreport/volume02/index.html*, IBR approved for §98.123(c)(1)(i)(A).

(5) Protocol for Equipment Leak Emission Estimates, EPA–453/R–95–017, November 1995 (EPA–453/R–95–017), *http://www.epa.gov/ttnchie1/efdocs/equiplks.pdf*, IBR approved for §98.123(d)(1)(i), §98.123(d)(1)(ii), §98.123(d)(1)(iii), and §98.124(f)(2).

(6) Tracer Gas Protocol for the Determination of Volumetric Flow Rate Through the Ring Pipe of the Xact Multi-Metals Monitoring System, also known as Other Test Method 24 (Tracer Gas Protocol), Eli Lilly and Company Tippecanoe Laboratories, September 2006, *http://www.epa.gov/ttn/emc/prelim/otm24.pdf*, IBR approved for §98.124(e)(1)(ii).

(7) Approved Alternative Method 012: An Alternate Procedure for Stack Gas Volumetric Flow Rate Determination (Tracer Gas) (ALT–012), U.S. Environmental Protection Agency Emission Measurement Center, May 23, 1994, *http://www.epa.gov/ttn/emc/approalt/alt-012.pdf*, IBR approved for §98.124(e)(1)(ii).

(8) Protocol for Measurement of Tetrafluoromethane (CF_4) and Hexafluoroethane (C_2F_6) Emissions from Primary Aluminum Production (2008), *http://www.epa.gov/highgwp/aluminum-pfc/documents/measureprotocol.pdf*, IBR approved for §98.64(a).

(9) AP 42, Section 5.2, Transportation and Marketing of Petroleum Liquids, July 2008, (AP 42, Section 5.2); *http://www.epa.gov/ttn/chief/ap42/ch05/final/c05s02.pdf*; in Chapter 5, Petroleum Industry, of AP 42, Compilation of Air Pollutant Emission Factors, 5th Edition, Volume I, IBR approved for §98.253(n).

(10) Method 9060A, Total Organic Carbon, Revision 1, November 2004 (Method 9060A), *http://www.epa.gov/osw/hazard/testmethods/sw846/pdfs/9060a.pdf*; in EPA Publication No. SW–846, ''Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,'' Third Edition, IBR approved for §98.244(b)(4)(viii).

(11) Method 8031, Acrylonitrile By Gas Chromatography, Revision 0, September 1994 (Method 8031), *http://www.epa.gov/osw/hazard/testmethods/sw846/pdfs/8031.pdf;* in EPA Publication No. SW–846, ''Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,'' Third Edition, IBR approved for §98.244(b)(4)(viii).

(12) Method 8021B, Aromatic and Halogenated Volatiles By Gas Chromatography Using Photoionization and/or Electrolytic Conductivity Detectors, Revision 2, December 1996 (Method 8021B). *http://www.epa.gov/osw/hazard/testmethods/sw846/pdfs/8021b.pdf*; in EPA Publication No. SW–846, ''Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,'' Third Edition, IBR approved for §98.244(b)(4)(viii).

(13) Method 8015C, Nonhalogenated Organics By Gas Chromatography, Revision 3, February 2007 (Method 8015C). *http://www.epa.gov/osw/hazard/testmethods/sw846/pdfs/8015c.pdf*; in EPA Publication No. SW–846, ''Test Methods for Evaluating Solid Waste, Physical/Chemical Methods,'' Third Edition, IBR approved for §98.244(b)(4)(viii).

(14) AP 42, Section 7.1, Organic Liquid Storage Tanks, November 2006 (AP 42, Section 7.1), *http://www.epa.gov/ttn/chief/ap42/ch07/final/c07s01.pdf*; in Chapter 7, Liquid Storage Tanks, of AP 42, Compilation of Air Pollutant Emission Factors, 5th Edition, Volume I, IBR approved for §98.253(m)(1) and §98.256(o)(2)(i).

(n)–(o) [Reserved]

(p) The following material is available for purchase from the American Association of Petroleum Geologists, 1444 South Boulder Avenue, Tulsa, Oklahoma 74119, (918) 584–2555, *http://www.aapg.org*.

(1) Geologic Note: AAPG–CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991), pages 1644–1651, IBR approved for §98.238.

(2) Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in cooperation with the USGS, 1978, IBR approved for §98.238.

(q) The following material is available from the Energy Information Administration (EIA), 1000 Independence Ave., SW., Washington, DC 20585, (202) 586–8800, *http://www.eia.doe.gov/pub/oil__gas/natural__gas/data__publications/field__code__master__list/current/pdf/fcml__all.pdf*.

(1) Oil and Gas Field Code Master List 2008, DOE/EIA0370(08), January 2009, IBR approved for §98.238.

(2) [Reserved]

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 39759, July 12, 2010; 75 FR 66458, Oct. 28, 2010; 75 FR 74488, Nov. 30, 2010; 75 FR 74816, Dec. 1, 2010; 75 FR 79138, Dec. 17, 2010; 78 FR 68202, Nov. 13, 2013; 78 FR 71948, Nov. 29, 2013]

§98.8 What are the compliance and enforcement provisions of this part?

Any violation of any requirement of this part shall be a violation of the Clean Air Act, including section 114 (42 U.S.C. 7414). A violation includes but is not limited to failure to report GHG emissions, failure to collect data needed to calculate GHG emissions, failure to continuously monitor and test as required, failure to retain records needed to verify the amount of GHG emissions, and failure to calculate GHG emissions following the methodologies specified in this part. Each day of a violation constitutes a separate violation.

§98.9 Addresses.

All requests, notifications, and communications to the Administrator pursuant to this part must be submitted electronically and in a format as specified by the Administrator. For example, any requests, notifications and communications that can be submitted through the electronic GHG reporting tool, must be submitted through that tool. If not specified, requests, notifications or communications shall be submitted to the following address:

(a) For U.S. mail. Director, Climate Change Division, 1200 Pennsylvania Ave., NW., Mail Code: 6207J, Washington, DC 20460.

(b) For package deliveries. Director, Climate Change Division, 1310 L St, NW., Washington, DC 20005.

[74 FR 56374, Oct. 30, 2009, as amended at 76 FR 73900, Nov. 29, 2011]

TABLE A–1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS

GLOBAL WARMING POTENTIALS

[100-Year Time Horizon]

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Carbon dioxide	124–38–9	CO_2	1
Methane	74–82–8	CH_4	[a]25
Nitrous oxide	10024–97–2	N_2O	[a]298
HFC–23	75–46–7	CHF_3	[a]14,800
HFC–32	75–10–5	CH_2F_2	[a]675
HFC–41	593–53–3	CH_3F	[a]92
HFC–125	354–33–6	C_2HF_5	[a]3,500
HFC–134	359–35–3	$C_2H_2F_4$	[a]1,100
HFC–134a	811–97–2	CH_2FCF_3	[a]1,430
HFC–143	430–66–0	$C_2H_3F_3$	[a]353
HFC–143a	420–46–2	$C_2H_3F_3$	[a]4,470
HFC–152	624–72–6	CH_2FCH_2F	53

GLOBAL WARMING POTENTIALS—Continued

[100-Year Time Horizon]

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
HFC–152a	75–37–6	CH_3CHF_2	[a] 124
HFC–161	353–36–6	CH_3CH_2F	12
HFC–227ea	431–89–0	C_3HF_7	[a] 3,220
HFC–236cb	677–56–5	$CH_2FCF_2CF_3$	1,340
HFC–236ea	431–63–0	CHF_2CHFCF_3	1,370
HFC–236fa	690–39–1	$C_3H_2F_6$	[a] 9,810
HFC–245ca	679–86–7	$C_3H_3F_5$	[a] 693
HFC–245fa	460–73–1	$CHF_2CH_2CF_3$	1,030
HFC–365mfc	406–58–6	$CH_3CF_2CH_2CF_3$	794
HFC–43–10mee	138495–42–8	$CF_3CFHCFHCF_2CF_3$	[a] 1,640
Sulfur hexafluoride	2551–62–4	SF_6	[a] 22,800
Trifluoromethyl sulphur pentafluoride	373–80–8	SF_5CF_3	17,700
Nitrogen trifluoride	7783–54–2	NF_3	17,200
PFC–14 (Perfluoromethane)	75–73–0	CF_4	[a] 7,390
PFC–116 (Perfluoroethane)	76–16–4	C_2F_6	[a] 12,200
PFC–218 (Perfluoropropane)	76–19–7	C_3F_8	[a] 8,830
Perfluorocyclopropane	931–91–9	$C–C_3F_6$	17,340
PFC–3–1–10 (Perfluorobutane)	355–25–9	C_4F_{10}	[a] 8,860
PFC–318 (Perfluorocyclobutane)	115–25–3	$C–C_4F_8$	[a] 10,300
PFC–4–1–12 (Perfluoropentane)	678–26–2	C_5F_{12}	[a] 9,160
PFC–5–1–14 (Perfluorohexane, FC–72)	355–42–0	C_6F_{14}	[a] 9,300
PFC–9–1–18	306–94–5	$C_{10}F_{18}$	7,500
HCFE–235da2 (Isoflurane)	26675–46–7	$CHF_2OCHClCF_3$	350
HFE–43–10pccc (H–Galden 1040x, HG–11).	E1730133	$CHF_2OCF_2OC_2F_4OCHF_2$	1,870
HFE–125	3822–68–2	CHF_2OCF_3	14,900
HFE–134 (HG–00)	1691–17–4	CHF_2OCHF_2	6,320
HFE–143a	421–14–7	CH_3OCF_3	756
HFE–227ea	2356–62–9	$CF_3CHFOCF_3$	1,540
HFE–236ca12 (HG–10)	78522–47–1	$CHF_2OCF_2OCHF_2$	2,800
HFE–236ea2 (Desflurane)	57041–67–5	$CHF_2OCHFCF_3$	989
HFE–236fa	20193–67–3	$CF_3CH_2OCF_3$	487
HFE–245cb2	22410–44–2	$CH_3OCF_2CF_3$	708
HFE–245fa1	84011–15–4	$CHF_2CH_2OCF_3$	286
HFE–245fa2	1885–48–9	$CHF_2OCH_2CF_3$	659
HFE–254cb2	425–88–7	$CH_3OCF_2CHF_2$	359
HFE–263fb2	460–43–5	$CF_3CH_2OCH_3$	11
HFE–329mcc2	134769–21–4	$CF_3CF_2OCF_2CHF_2$	919
HFE–338mcf2	156053–88–2	$CF_3CF_2OCH_2CF_3$	552
HFE–338pcc13 (HG–01)	188690–78–0	$CHF_2OCF_2CF_2OCHF_2$	1,500
HFE–347mcc3 (HFE–7000)	375–03–1	$CH_3OCF_2CF_2CF_3$	575
HFE–347mcf2	171182–95–9	$CF_3CF_2OCH_2CHF_2$	374
HFE–347pcf2	406–78–0	$CHF_2CF_2OCH_2CF_3$	580
HFE–356mec3	382–34–3	$CH_3OCF_2CHFCF_3$	101
HFE–356pcc3	160620–20–2	$CH_3OCF_2CF_2CHF_2$	110
HFE–356pcf2	50807–77–7	$CHF_2CH_2OCF_2CHF_2$	265
HFE–356pcf3	35042–99–0	$CHF_2OCH_2CF_2CHF_2$	502
HFE–365mcf3	378–16–5	$CF_3CF_2CH_2OCH_3$	11
HFE–374pc2	512–51–6	$CH_3CH_2OCF_2CHF_2$	557
HFE–449s1 (HFE–7100)	163702–07–6	$C_4F_9OCH_3$	297
Chemical blend	163702–08–7	$(CF_3)_2CFCF_2OCH_3$.	
HFE–569sf2 (HFE–7200)	163702–05–4	$C_4F_9OC_2H_5$	59
Chemical blend	163702–06–5	$(CF_3)_2CFCF_2OC_2H_5$.	
Sevoflurane (HFE–347mmz1)	28523–86–6	$CH_2FOCH(CF_3)_2$	345
HFE–356mm1	13171–18–1	$(CF_3)_2CHOCH_3$	27
HFE–338mmz1	26103–08–2	$CHF_2OCH(CF_3)_2$	380
(Octafluorotetramethy-lene) hydroxymethyl group.	NA	$X-(CF_2)_4CH(OH)-X$	73
HFE–347mmy1	22052–84–2	$CH_3OCF(CF_3)_2$	343
Bis(trifluoromethyl)-methanol	920–66–1	$(CF_3)_2CHOH$	195
2,2,3,3,3-pentafluoropropanol	422–05–9	$CF_3CF_2CH_2OH$	42
PFPMIE (HT–70)	NA	$CF_3OCF(CF_3)CF_2OCF_2OCF_3$	10,300

[a] The GWP for this compound is different than the GWP in the version of Table A–1 to subpart A of part 98 published on October 30, 2009.

[78 FR 71948, Nov. 29, 2013]

TABLE A–2 TO SUBPART A OF PART 98—UNITS OF MEASURE CONVERSIONS

To convert from	To	Multiply by
Kilograms (kg)	Pounds (lbs)	2.20462
Pounds (lbs)	Kilograms (kg)	0.45359
Pounds (lbs)	Metric tons	4.53592×10^{-4}
Short tons	Pounds (lbs)	2,000
Short tons	Metric tons	0.90718
Metric tons	Short tons	1.10231
Metric tons	Kilograms (kg)	1,000
Cubic meters (m^3)	Cubic feet (ft^3)	35.31467
Cubic feet (ft^3)	Cubic meters (m^3)	0.028317
Gallons (liquid, US)	Liters (l)	3.78541
Liters (l)	Gallons (liquid, US)	0.26417
Barrels of Liquid Fuel (bbl)	Cubic meters (m^3)	0.15891
Cubic meters (m^3)	Barrels of Liquid Fuel (bbl)	6.289
Barrels of Liquid Fuel (bbl)	Gallons (liquid, US)	42
Gallons (liquid, US)	Barrels of Liquid Fuel (bbl)	0.023810
Gallons (liquid, US)	Cubic meters (m^3)	0.0037854
Liters (l)	Cubic meters (m^3)	0.001
Feet (ft)	Meters (m)	0.3048
Meters (m)	Feet (ft)	3.28084
Miles (mi)	Kilometers (km)	1.60934
Kilometers (km)	Miles (mi)	0.62137
Square feet (ft^2)	Acres	2.29568×10^{-5}
Square meters (m^2)	Acres	2.47105×10^{-4}
Square miles (mi^2)	Square kilometers (km^2)	2.58999
Degrees Celsius (°C)	Degrees Fahrenheit (°F)	$°C = (5/9) \times (°F - 32)$
Degrees Fahrenheit (°F)	Degrees Celsius (°C)	$°F = (9/5) \times °C + 32$
Degrees Celsius (°C)	Kelvin (K)	$K = °C + 273.15$
Kelvin (K)	Degrees Rankine (°R)	1.8
Joules	Btu	9.47817×10^{-4}
Btu	MMBtu	1×10^{-6}
Pascals (Pa)	Inches of Mercury (in Hg)	2.95334×10^{-4}
Inches of Mercury (inHg)	Pounds per square inch (psi)	0.49110
Pounds per square inch (psi)	Inches of Mercury (in Hg)	2.03625

TABLE A–3 TO SUBPART A OF PART 98—SOURCE CATEGORY LIST FOR § 98.2(a)(1)

SOURCE CATEGORY LIST FOR § 98.2(a)(1)

Source Categories[a] Applicable in 2010 and Future Years

- Electricity generation units that report CO_2 mass emissions year round through 40 CFR part 75 (subpart D).
- Adipic acid production (subpart E).
- Aluminum production (subpart F).
- Ammonia manufacturing (subpart G).
- Cement production (subpart H).
- HCFC–22 production (subpart O).
- HFC–23 destruction processes that are not collocated with a HCFC–22 production facility and that destroy more than 2.14 metric tons of HFC–23 per year (subpart O).
- Lime manufacturing (subpart S).
- Nitric acid production (subpart V).
- Petrochemical production (subpart X).
- Petroleum refineries (subpart Y).
- Phosphoric acid production (subpart Z).
- Silicon carbide production (subpart BB).
- Soda ash production (subpart CC).
- Titanium dioxide production (subpart EE).
- Municipal solid waste landfills that generate CH_4 in amounts equivalent to 25,000 metric tons CO_2e or more per year, as determined according to subpart HH of this part.
- Manure management systems with combined CH_4 and N_2O emissions in amounts equivalent to 25,000 metric tons CO_2e or more per year, as determined according to subpart JJ of this part.

Additional Source Categories[a] Applicable in 2011 and Future Years

Electrical transmission and distribution equipment use at facilities where the total nameplate capacity of SF_6 and PFC containing equipment exceeds 17,820 pounds, as determined under § 98.301 (subpart DD).

Underground coal mines liberating 36,500,000 actual cubic feet of CH_4 or more per year (subpart FF).

Geologic sequestration of carbon dioxide (subpart RR).

- Electrical transmission and distribution equipment manufacture or refurbishment (subpart SS).

Injection of carbon dioxide (subpart UU).

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[a] Source categories are defined in each applicable subpart.

[75 FR 39760, July 12, 2010, as amended at 75 FR 74817, 75078, Dec. 1, 2010; 76 FR 73900, Nov. 29, 2011]

TABLE A–4 TO SUBPART A OF PART 98—SOURCE CATEGORY LIST FOR § 98.2(a)(2)

TABLE A–4 TO SUBPART A—SOURCE CATEGORY LIST FOR § 98.2(a)(2)

- Source Categories[a] Applicable in 2010 and Future Years
    - Ferroalloy production (subpart K).
    - Glass production (subpart N).
    - Hydrogen production (subpart P).
    - Iron and steel production (subpart Q).
    - Lead production (subpart R).
    - Pulp and paper manufacturing (subpart AA).
    - Zinc production (subpart GG).
- Additional Source Categories[a] Applicable in 2011 and Future Years
- Electronics manufacturing (subpart I)
- Fluorinated gas production (subpart L)
    - Magnesium production (subpart T).
    - Petroleum and Natural Gas Systems (subpart W)
    - Industrial wastewater treatment (subpart II).
    - Industrial waste landfills (subpart TT).

[a] Source categories are defined in each applicable subpart.

[75 FR 39760, July 12, 2010, as amended at 75 FR 74488, Nov. 30, 2010; 75 FR 74817, Dec. 1, 2010]

TABLE A–5 TO SUBPART A OF PART 98—SUPPLIER CATEGORY LIST FOR § 98.2(a)(4)

TABLE A–5 TO SUBPART A—SUPPLIER CATEGORY LIST FOR § 98.2(a)(4)

- Supplier Categories[a] Applicable in 2010 and Future Years
    - Coal-to-liquids suppliers (subpart LL):
        - (A) All producers of coal-to-liquid products.
        - (B) Importers of an annual quantity of coal-to-liquid products that is equivalent to 25,000 metric tons CO_2e or more.
        - (C) Exporters of an annual quantity of coal-to-liquid products that is equivalent to 25,000 metric tons CO_2e or more.
    - Petroleum product suppliers (subpart MM):
        - (A) All petroleum refineries that distill crude oil.
        - (B) Importers of an annual quantity of petroleum products and natural gas liquids that is equivalent to 25,000 metric tons CO_2e or more.
        - (C) Exporters of an annual quantity of petroleum products and natural gas liquids that is equivalent to 25,000 metric tons CO_2e or more.
    - Natural gas and natural gas liquids suppliers (subpart NN):
        - (A) All fractionators.
        - (B) Local natural gas distribution companies that deliver 460,000 thousand standard cubic feet or more of natural gas per year.
    - Industrial greenhouse gas suppliers (subpart OO):
        - (A) All producers of industrial greenhouse gases.
        - (B) Importers of industrial greenhouse gases with annual bulk imports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.
        - (C) Exporters of industrial greenhouse gases with annual bulk exports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.
    - Carbon dioxide suppliers (subpart PP):
        - (A) All producers of CO_2.
        - (B) Importers of CO_2 with annual bulk imports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.
        - (C) Exporters of CO_2 with annual bulk exports of N_2O, fluorinated GHG, and CO_2 that in combination are equivalent to 25,000 metric tons CO_2e or more.
- Additional Supplier Categories Applicable[a] in 2011 and Future Years
- Importers and exporters of fluorinated greenhouse gases contained in pre-charged equipment or closed-cell foams (subpart QQ):
    - (A) Importers of an annual quantity of fluorinated greenhouse gases contained in pre-charged equipment or closed-cell foams that is equivalent to 25,000 metric tons CO_2e or more.
    - (B) Exporters of an annual quantity of fluorinated greenhouse gases contained in pre-charged equipment or closed-cell foams that is equivalent to 25,000 metric tons CO_2e or more.

[a] Suppliers are defined in each applicable subpart.

[75 FR 39760, July 12, 2010, as amended at 75 FR 74817, Dec. 1, 2010; 75 FR 79140, Dec. 17, 2010; 76 FR 73901, Nov. 29, 2011]

Table A–6 to Subpart A of Part 98—Data Elements That Are Inputs to Emission Equations and for Which the Reporting Deadline Is March 31, 2013

Subpart	Rule citation (40 CFR part 98)	Specific data elements for which reporting date is March 31, 2013 (“All” means all data elements in the cited paragraph are not required to be reported until March 31, 2013)
C	98.36(d)(1)(iv)	All.
C	98.36(d)(2)(ii)(G)	All.
C	98.36(d)(2)(iii)(G)	All.
C	98.36(e)(2)(iv)(G)	All.
C	98.36(e)(2)(viii)(A)	All.
C	98.36(e)(2)(viii)(B)	All.
C	98.36(e)(2)(viii)(C)	All.
C	98.36(e)(2)(x)(A)	All.
C	98.36(e)(2)(xi)	All.
DD	98.306(a)(2)	All.
DD	98.306(a)(3)	All.
DD	98.306(d)	All.
DD	98.306(e)	All.
DD	98.306(f)	All.
DD	98.306(g)	All.
DD	98.306(h)	All.
DD	98.306(i)	All.
DD	98.306(j)	All.
DD	98.306(k)	All.
DD	98.306(l)	All.
FF	98.326(a)	All.
FF	98.326(b)	All.
FF	98.326(c)	All.
FF	98.326(f)	Only quarterly volumetric flow rate.
FF	98.326(g)	Only quarterly CH_4 concentration.
FF	98.326(h)	Only weekly volumetric flow used to calculate CH_4 liberated from degasification systems.
FF	98.326(j)	All.
FF	98.326(k)	All.
FF	98.326(o)	All.
FF	98.326(p)	Only assumed destruction efficiency for the primary destruction device and assumed destruction efficiency for the backup destruction device.
HH	98.346(a)	Only year in which landfill first accepted waste, last year the landfill accepted waste (if used as an input in Equation HH–3), capacity of the landfill (if used as an input in Equation HH–3), and waste disposal quantity for each year of landfilling.
HH	98.346(b)	Only quantity of waste determined using the methods in § 98.343(a)(3)(i), quantity of waste determined using the methods in § 98.343(a)(3)(ii), population served by the landfill for each year, and the value of landfill capacity (LFC) used in the calculation.
HH	98.346(c)	All.
HH	98.346(d)(1)	Only degradable organic carbon (DOC) value, and fraction of DOC dissimilated (DOCF) values.
HH	98.346(d)(2)	All.
HH	98.346(e)	Only fraction of CH_4 in landfill gas and methane correction factor (MCF) values.
HH	98.346(f)	Only surface area associated with each cover type.
HH	98.346(g)	All.
HH	98.346(i)(5)	Only annual operating hours for the destruction devices located at the landfill facility, and the destruction efficiency for the destruction devices associated with that measurement location.
HH	98.346(i)(6)	All.
HH	98.346(i)(7)	Only surface area specified in Table HH–3, estimated gas collection system efficiency, and annual operating hours of the gas collection system for each measurement locations.
HH	98.346(i)(9)	Only CH_4 generation value.
II	98.356(b)(1)	All.
II	98.356(b)(2)	All.
II	98.356(b)(3)	All.
II	98.356(b)(4)	All.
II	98.356(b)(5)	All.
II	98.356(d)(1)	All.
II	98.356(d)(7)	All.
II	98.356(d)(8)	Only annual operating hours for the primary destruction device, annual operating hours for the backup destruction device, destruction efficiency of the primary destruction device, and destruction efficiency of the backup destruction device.
SS	98.456(a)	All.

Subpart	Rule citation (40 CFR part 98)	Specific data elements for which reporting date is March 31, 2013 ("All" means all data elements in the cited paragraph are not required to be reported until March 31, 2013)
SS	98.456(b)	All.
SS	98.456(c)	All.
SS	98.456(d)	All.
SS	98.456(e)	All.
SS	98.456(f)	All.
SS	98.456(g)	All.
SS	98.456(h)	All.
SS	98.456(i)	All.
SS	98.456(j)	All.
SS	98.456(m)	All.
SS	98.456(n)	All.
SS	98.456(o)	All.
SS	98.456(q)	All.
SS	98.456(r)	All.
SS	98.456(s)	All.
SS	98.456(t)	Only for any missing data the substitute parameters used to estimate emissions in their absence.
TT	98.466(a)(2)	All.
TT	98.466(a)(3)	Only last year the landfill accepted waste (for closed landfills using Equation TT–4).
TT	98.466(a)(4)	Only capacity of the landfill in metric tons (for closed landfills using Equation TT–4).
TT	98.466(b)(3)	Only fraction of CH_4 in landfill gas.
TT	98.466(b)(4)	Only the methane correction factor (MCF) value used in the calculations.
TT	98.466(c)(4)(i)	All.
TT	98.466(c)(4)(ii)	All.
TT	98.466(c)(4)(iii)	All.
TT	98.466(d)(2)	All.
TT	98.466(d)(3)	Only degradable organic carbon (DOCx) value for each waste stream used in calculations.
TT	98.466(e)(2)	Only surface area (in square meters) at the start of the reporting year for the landfill sections that contain waste and that are associated with the selected cover type (for facilities using a landfill gas collection system).
TT	98.466(f)	All.

[76 FR 53065, Aug. 25, 2011, as amended at 77 FR 48088, Aug. 13, 2012; 78 FR 71949, Nov. 29, 2013]

TABLE A–7 TO SUBPART A OF PART 98—DATA ELEMENTS THAT ARE INPUTS TO EMISSION EQUATIONS AND FOR WHICH THE REPORTING DEADLINE IS MARCH 31, 2015

Subpart	Rule citation (40 CFR part 98)	Specific data elements for which reporting date is March 31, 2015 ("All" means all data elements in the cited paragraph are not required to be reported until March 31, 2015)
A	98.3(d)(3)(v)	All.
C	98.36(b)(9)(iii)	Only estimate of the heat input.
C	98.36(c)(2)(ix)	Only estimate of the heat input from each type of fuel listed in Table C–2.
C	98.36(e)(2)(i)	All.
C	98.36(e)(2)(ii)(A)	All.
C	98.36(e)(2)(ii)(C)	Only HHV value for each calendar month in which HHV determination is required.
C	98.36(e)(2)(ii)(D)	All.
C	98.36(e)(2)(iv)(A)	All.
C	98.36(e)(2)(iv)(C)	All.
C	98.36(e)(2)(iv)(F)	All.
C	98.36(e)(2)(ix)(D)	All.
C	98.36(e)(2)(ix)(E)	All.
C	98.36(e)(2)(ix)(F)	All.
E	98.56(b)	All.
E	98.56(c)	All.
E	98.56(g)	All.
E	98.56(h)	All.
E	98.56(j)(1)	All.
E	98.56(j)(3)	All.
E	98.56(j)(4)	All.
E	98.56(j)(5)	All.
E	98.56(j)(6)	All.
E	98.56(l)	All.

Subpart	Rule citation (40 CFR part 98)	Specific data elements for which reporting date is March 31, 2015 ("All" means all data elements in the cited paragraph are not required to be reported until March 31, 2015)
F	98.66(a)	All.
F	98.66(c)(2)	All.
F	98.66(c)(3)	Only smelter-specific slope coefficients and overvoltage emission factors.
F	98.66(e)(1)	Only annual anode consumption (No CEMS).
F	98.66(f)(1)	Only annual paste consumption (No CEMS).
F	98.66(g)	All.
G	98.76(b)(2)	All.
G	98.76(b)(7)	All.
G	98.76(b)(8)	All.
G	98.76(b)(9)	All.
G	98.76(b)(10)	All.
G	98.76(b)(11)	All.
H	98.86(b)(2)	All.
H	98.86(b)(5)	All.
H	98.86(b)(6)	All.
H	98.86(b)(8)	All.
H	98.86(b)(10)	All.
H	98.86(b)(11)	All.
H	98.86(b)(12)	All.
H	98.86(b)(13)	All.
H	98.86(b)(15)	Only monthly kiln-specific clinker factors (if used) for each kiln.
I	98.96(f)(1)	All.
K	98.116(b)	Only annual production by product from each EAF (No CEMS).
K	98.116(e)(4)	All.
K	98.116(e)(5)	All.
L	98.126(b)(1)	Only data used in calculating the absolute errors and data used in calculating the relative errors.
L	98.126(b)(2)	All.
L	98.126(b)(6)	Only mass of each fluorine-containing reactant fed into the process.
L	98.126(b)(7)	Only mass of each fluorine-containing product produced by the process.
L	98.126(b)(8)(i)	Only mass of each fluorine-containing product that is removed from the process and fed into the destruction device.
L	98.126(b)(8)(ii)	Only mass of each fluorine-containing by-product that is removed from the process and fed into the destruction device.
L	98.126(b)(8)(iii)	Only mass of each fluorine-containing reactant that is removed from the process and fed into the destruction device.
L	98.126(b)(8)(iv)	Only mass of each fluorine-containing by-product that is removed from the process and recaptured.
L	98.126(b)(8)(v)	All.
L	98.126(b)(9)(i)	All.
L	98.126(b)(9)(ii)	All.
L	98.126(b)(9)(iii)	All.
L	98.126(b)(10)	All.
L	98.126(b)(11)	All.
L	98.126(b)(12)	All.
L	98.126(c)(1)	Only quantity of the process activity used to estimate emissions.
L	98.126(c)(2)	All.
L	98.126(d)	Only estimate of missing data.
L	98.126(f)(1)	All.
L	98.126(g)(1)	All.
L	98.126(h)(2)	All.
N	98.146(b)(2)	Only annual quantity of carbonate based-raw material charged to each continuous glass melting furnace.
N	98.146(b)(4)	All.
N	98.146(b)(6)	All.
O	98.156(a)(2)	All.
O	98.156(a)(7)	All.
O	98.156(a)(8)	All.
O	98.156(a)(9)	All.
O	98.156(a)(10)	All.
O	98.156(b)(1)	All.
O	98.156(b)(2)	All.
O	98.156(d)(1)	All.
O	98.156(d)(2)	All.
O	98.156(d)(3)	All.
O	98.156(d)(4)	All.
O	98.156(d)(5)	All.
O	98.156(e)(1)	All.
P	98.166(b)(2)	All.
P	98.166(b)(5)	All.

Subpart	Rule citation (40 CFR part 98)	Specific data elements for which reporting date is March 31, 2015 (“All” means all data elements in the cited paragraph are not required to be reported until March 31, 2015)
P	98.166(b)(6)	All.
Q	98.176(b)	Only annual quantity taconite pellets, coke, iron, and raw steel (No CEMS).
Q	98.176(e)(1)	All.
Q	98.176(e)(3)	All.
Q	98.176(e)(4)	All.
Q	98.176(f)(1)	All.
Q	98.176(f)(2)	All.
Q	98.176(f)(3)	All.
Q	98.176(f)(4)	All.
Q	98.176(g)	All.
R	98.186(b)(6)	All.
R	98.186(b)(7)	All.
S	98.196(b)(2)	All.
S	98.196(b)(3)	All.
S	98.196(b)(5)	All.
S	98.196(b)(6)	All.
S	98.196(b)(8)	All.
S	98.196(b)(10)	All.
S	98.196(b)(11)	All.
S	98.196(b)(12)	All.
U	98.216(b)	All.
U	98.216(e)(1)	All.
U	98.216(e)(2)	All.
U	98.216(f)(1)	All.
U	98.216(f)(2)	All.
V	98.226(c)	All.
V	98.226(d)	All.
V	98.226(i)	All.
V	98.226(j)	All.
V	98.226(m)(1)	All.
V	98.226(m)(3)	All.
V	98.226(m)(4)	All.
V	98.226(m)(5)	All.
V	98.226(m)(6)	All.
V	98.226(p)	All.
W	98.236(c)(1)(i)	All.
W	98.236(c)(1)(ii)	All.
W	98.236(c)(1)(iii)	All.
W	98.236(c)(2)(i)	All.
W	98.236(c)(3)(i)	All.
W	98.236(c)(3)(ii)	Only Calculation Methodology 2.
W	98.236(c)(3)(iii)	All.
W	98.236(c)(3)(iv)	All.
W	98.236(c)(4)(i)(A)	All.
W	98.236(c)(4)(i)(B)	All.
W	98.236(c)(4)(i)(C)	All.
W	98.236(c)(4)(i)(D)	All.
W	98.236(c)(4)(i)(E)	All.
W	98.236(c)(4)(i)(F)	All.
W	98.236(c)(4)(i)(G)	All.
W	98.236(c)(4)(i)(H)	All.
W	98.236(c)(4)(ii)(A)	All.
W	98.236(c)(5)(i)(D)	All.
W	98.236(c)(5)(ii)(C)	All.
W	98.236(c)(6)(i)(B)	All.
W	98.236(c)(6)(i)(D)	All.
W	98.236(c)(6)(i)(E)	All.
W	98.236(c)(6)(i)(F)	All.
W	98.236(c)(6)(i)(G)	Only the amount of natural gas required.
W	98.236(c)(6)(i)(H)	Only the amount of natural gas required.
W	98.236(c)(6)(ii)(A)	All.
W	98.236(c)(6)(ii)(B)	All.
W	98.236(c)(7)(i)(A)	Only for Equation W–14A.
W	98.236(c)(8)(i)(F)	All.
W	98.236(c)(8)(i)(K)	All.
W	98.236(c)(8)(ii)(A)	All.
W	98.236(c)(8)(ii)(H)	All.
W	98.236(c)(8)(iii)(A)	All.
W	98.236(c)(8)(iii)(B)	All.
W	98.236(c)(8)(iii)(G)	All.
W	98.236(c)(12)(ii)	All.

Subpart	Rule citation (40 CFR part 98)	Specific data elements for which reporting date is March 31, 2015 (“All” means all data elements in the cited paragraph are not required to be reported until March 31, 2015)
W	98.236(c)(12)(v)	All.
W	98.236(c)(13)(i)(E)	All.
W	98.236(c)(13)(i)(F)	All.
W	98.236(c)(13)(ii)(A)	All.
W	98.236(c)(13)(ii)(B)	All.
W	98.236(c)(13)(iii)(A)	All.
W	98.236(c)(13)(iii)(B)	All.
W	98.236(c)(13)(v)(A)	All.
W	98.236(c)(14)(i)(B)	All.
W	98.236(c)(14)(ii)(A)	All.
W	98.236(c)(14)(ii)(B)	All.
W	98.236(c)(14)(iii)(A)	All.
W	98.236(c)(14)(iii)(B)	All.
W	98.236(c)(14)(v)(A)	All.
W	98.236(c)(15)(ii)(A)	All.
W	98.236(c)(15)(ii)(B)	All.
W	98.236(c)(16)(viii)	All.
W	98.236(c)(16)(ix)	All.
W	98.236(c)(16)(x)	All.
W	98.236(c)(16)(xi)	All.
W	98.236(c)(16)(xii)	All.
W	98.236(c)(16)(xiii)	All.
W	98.236(c)(16)(xiv)	All.
W	98.236(c)(16)(xv)	All.
W	98.236(c)(16)(xvi)	All.
W	98.236(c)(17)(ii)	All.
W	98.236(c)(17)(iii)	All.
W	98.236(c)(17)(iv)	All.
W	98.236(c)(18)(i)	All.
W	98.236(c)(18)(ii)	All.
W	98.236(c)(19)(iv)	All.
W	98.236(c)(19)(vii)	All.
X	98.246(a)(4)	Only monthly volume values, monthly mass values, monthly carbon content values, molecular weights for gaseous feedstocks, molecular weights for gaseous products, and indication of whether the alternative method in § 98.243(c)(4) was used.
X	98.246(b)(5)(iii)	All.
X	98.246(b)(5)(iv)	All.
Y	98.256(e)(6)	Only molar volume conversion factor for each flare.
Y	98.256(e)(7)	Only molar volume conversion factor for each flare.
Y	98.256(e)(7)(ii)	All.
Y	98.256(e)(9)	Only annual volume of flare gas combusted, annual average higher heating value of the flare gas, volume of gas flared, average molecular weight, carbon content of the flare, and molar volume conversion factor if using Eq. Y–3.
Y	98.256(e)(10)	Only fraction of carbon in the flare gas contributed by methane.
Y	98.256(f)(7)	Only molar volume conversion factor.
Y	98.256(f)(10)	Only coke burn-off factor, annual throughput of unit, and average carbon content of coke.
Y	98.256(f)(11)	Only units of measure for the unit-specific CH_4 emission factor, activity data for calculating emissions, and unit-specific emission factor for CH_4.
Y	98.256(f)(12)	Only unit-specific emission factor for N_2O, units of measure for the unit-specific N_2O emission factor, and activity data for calculating emissions.
Y	98.256(f)(13)	Only average carbon content of coke.
Y	98.256(h)(4)	All.
Y	98.256(h)(5)	Only value of the correction, annual volume of recycled tail gas (if used to calculate recycling correction factor), and annual average mole fraction of carbon in the tail gas (if used to calculate recycling correction factor).
Y	98.256(i)(5)	Only annual mass of green coke fed, carbon content of green coke fed, annual mass of marketable coke produced, carbon content of marketable coke produced, and annual mass of coke dust removed from the process.
Y	98.256(i)(7)	Only the unit-specific CH_4 emission factor, units of measure for unit-specific CH_4 emission factor, and activity data for calculating emissions.
Y	98.256(i)(8)	Only units of measure for the unit-specific factor, activity data used for calculating emissions, and site-specific emissions factor.
Y	98.256(j)(2)	All.
Y	98.256(j)(5)	Only CO_2 emission factor.

Subpart	Rule citation (40 CFR part 98)	Specific data elements for which reporting date is March 31, 2015 (“All” means all data elements in the cited paragraph are not required to be reported until March 31, 2015)
Y	98.256(j)(6)	Only CH_4 emission factor.
Y	98.256(j)(7)	Only carbon emission factor.
Y	98.256(j)(8)	Only CO_2 emission factor and carbon emission factor.
Y	98.256(j)(9)	Only CH_4 emission factor.
Y	98.256(k)(3)	Only dimensions of coke drum or vessel, typical gauge pressure of the coking drum, typical void fraction of coke drum or vessel, annual number of coke-cutting cycles of coke drum or vessel, and molar volume conversion factor for each coke drum or vessel.
Y	98.256(k)(4)	Only height and diameter of the coke drums, cumulative number of vessel openings for all delayed coking drums, typical venting pressure, void fraction, mole fraction of methane in coking gas.
Y	98.256(l)(5)	Only molar volume conversion factor.
Y	98.256(m)(3)	Only total quantity of crude oil plus the quantity of intermediate products received from off-site, CH_4 emission factor used, and molar volume conversion factor.
Y	98.256(n)(3)	All (if used in Equation Y–21 to calculate emissions from equipment leaks).
Y	98.256(o)(2)(ii)	All.
Y	98.256(o)(4)(ii)	All.
Y	98.256(o)(4)(iii)	All.
Y	98.256(o)(4)(iv)	All.
Y	98.256(o)(4)(v)	All.
Y	98.256(o)(4)(vi)	Only tank-specific methane composition data and gas generation rate data.
Y	98.256(p)(2)	Only quantity of materials loaded that have an equilibrium vapor-phase concentration of CH_4 of 0.5 volume percent or greater.
Z	98.266(f)(5)	All.
Z	98.266(f)(6)	All.
AA	98.276(b)	All.
AA	98.276(c)	Only annual mass of the spent liquor solids combusted.
AA	98.276(d)	All.
AA	98.276(e)	All.
AA	98.276(f)	All.
AA	98.276(g)	All.
AA	98.276(h)	All.
AA	98.276(i)	All.
BB	98.286(b)(1)	All.
BB	98.286(b)(4)	All.
BB	98.286(b)(6)	All.
CC	98.296(b)(5)	Only monthly consumption of trona or liquid alkaline feedstock (for facilities using Equation CC–1).
CC	98.296(b)(6)	Only monthly production of soda ash for each manufacturing line(for facilities using Equation CC–2).
CC	98.296(b)(7)	All.
CC	98.296(b)(10)(i)	All.
CC	98.296(b)(10)(ii)	All.
CC	98.296(b)(10)(iii)	All.
CC	98.296(b)(10)(iv)	All.
CC	98.296(b)(10)(v)	All.
CC	98.296(b)(10)(vi)	All.
EE	98.316(b)(6)	All.
EE	98.316(b)(9)	All.
GG	98.336(b)(6)	All.
GG	98.336(b)(7)	All.
GG	98.336(b)(10)	All.
II	98.356(d)(2)	All (if conducting weekly sampling).
II	98.356(d)(3)	All (if conducting weekly sampling).
II	98.356(d)(4)	Only weekly average temperature (if conducting weekly sampling).
II	98.356(d)(5)	Only weekly average moisture content (if conducting weekly sampling).
II	98.356(d)(6)	Only weekly average pressure (if conducting weekly sampling).
TT	98.466(c)(3)(i)	All.
TT	98.466(c)(3)(ii)	Only waste disposal quantity and production quantity.
TT	98.466(c)(3)(iii)	All.

[76 FR 53065, Aug. 25, 2011, as amended at 77 FR 48088, Aug. 13, 2012; 77 FR 51489, Aug. 24, 2012; 78 FR 68202, Nov. 13, 2013; 78 FR 71950, Nov. 29, 2013]

Subpart B [Reserved]

Subpart C—General Stationary Fuel Combustion Sources

§ 98.30 Definition of the source category.

(a) Stationary fuel combustion sources are devices that combust solid, liquid, or gaseous fuel, generally for the purposes of producing electricity, generating steam, or providing useful heat or energy for industrial, commercial, or institutional use, or reducing the volume of waste by removing combustible matter. Stationary fuel combustion sources include, but are not limited to, boilers, simple and combined-cycle combustion turbines, engines, incinerators, and process heaters.

(b) This source category does not include:

(1) Portable equipment, as defined in § 98.6.

(2) Emergency generators and emergency equipment, as defined in § 98.6.

(3) Irrigation pumps at agricultural operations.

(4) Flares, unless otherwise required by provisions of another subpart of this part to use methodologies in this subpart.

(5) Electricity generating units that are subject to subpart D of this part.

(c) For a unit that combusts hazardous waste (as defined in § 261.3 of this chapter), reporting of GHG emissions is not required unless either of the following conditions apply:

(1) Continuous emission monitors (CEMS) are used to quantify CO_2 mass emissions.

(2) Any fuel listed in Table C–1 of this subpart is also combusted in the unit. In this case, report GHG emissions from combustion of all fuels listed in Table C–1 of this subpart.

(d) You are not required to report GHG emissions from pilot lights. A pilot light is a small auxiliary flame that ignites the burner of a combustion device when the control valve opens.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79140, Dec. 17, 2010]

§ 98.31 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more stationary fuel combustion sources and the facility meets the applicability requirements of either §§ 98.2(a)(1), 98.2(a)(2), or 98.2(a)(3).

§ 98.32 GHGs to report.

You must report CO_2, CH_4, and N_2O mass emissions from each stationary fuel combustion unit, except as otherwise indicated in this subpart.

[75 FR 79140, Dec. 17, 2010]

§ 98.33 Calculating GHG emissions.

You must calculate CO_2 emissions according to paragraph (a) of this section, and calculate CH_4 and N_2O emissions according to paragraph (c) of this section.

(a) *CO_2 emissions from fuel combustion.* Calculate CO_2 mass emissions by using one of the four calculation methodologies in paragraphs (a)(1) through (a)(4) of this section, subject to the applicable conditions, requirements, and restrictions set forth in paragraph (b) of this section. Alternatively, for units that meet the conditions of paragraph (a)(5) of this section, you may use CO_2 mass emissions calculation methods from part 75 of this chapter, as described in paragraph (a)(5) of this section. For units that combust both biomass and fossil fuels, you must calculate and report CO_2 emissions from the combustion of biomass separately using the methods in paragraph (e) of this section, except as otherwise provided in paragraphs (a)(5)(iv) and (e) of this section and in § 98.36(d).

(1) *Tier 1 Calculation Methodology.* Calculate the annual CO_2 mass emissions for each type of fuel by using Equation C–1, C–1a, or C–1b of this section (as applicable).

(i) Use Equation C–1 except when natural gas billing records are used to quantify fuel usage and gas consumption is expressed in units of therms or million Btu. In that case, use Equation C–1a or C–1b, as applicable.

$$CO_2 = 1 x 10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-1)}$$

where:

CO$_2$ = Annual CO$_2$ mass emissions for the specific fuel type (metric tons).

Fuel = Mass or volume of fuel combusted per year, from company records as defined in § 98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Default high heat value of the fuel, from Table C–1 of this subpart (mmBtu per mass or mmBtu per volume, as applicable).

EF = Fuel-specific default CO$_2$ emission factor, from Table C–1 of this subpart (kg CO$_2$/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(ii) If natural gas consumption is obtained from billing records and fuel usage is expressed in therms, use Equation C–1a.

$$CO_2 = 1 x 10^{-3} \left[0.1 * Gas * EF\right] \qquad \text{(Eq. C-1a)}$$

where:

CO$_2$ = Annual CO$_2$ mass emissions from natural gas combustion (metric tons).

Gas = Annual natural gas usage, from billing records (therms).

EF = Fuel-specific default CO$_2$ emission factor for natural gas, from Table C–1 of this subpart (kg CO$_2$/mmBtu).

0.1 = Conversion factor from therms to mmBtu

1×10^{-3} = Conversion factor from kilograms to metric tons.

(iii) If natural gas consumption is obtained from billing records and fuel usage is expressed in mmBtu, use Equation C–1b.

$$CO_2 = 1 x 10^{-3} * Gas * EF \qquad \text{(Eq. C-1b)}$$

where:

CO$_2$ = Annual CO$_2$ mass emissions from natural gas combustion (metric tons).

Gas = Annual natural gas usage, from billing records (mmBtu).

EF = Fuel-specific default CO$_2$ emission factor for natural gas, from Table C–1 of this subpart (kg CO$_2$/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(2) *Tier 2 Calculation Methodology*. Calculate the annual CO$_2$ mass emissions for each type of fuel by using either Equation C2a or C2c of this section, as appropriate.

(i) Equation C–2a of this section applies to any type of fuel listed in Table C–1 of the subpart, except for municipal solid waste (MSW). For MSW combustion, use Equation C–2c of this section.

$$CO_2 = 1 x 10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-2a)}$$

Where:

CO$_2$ = Annual CO$_2$ mass emissions for a specific fuel type (metric tons).

Fuel = Mass or volume of the fuel combusted during the year, from company records as defined in § 98.6 (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

HHV = Annual average high heat value of the fuel (mmBtu per mass or volume). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

EF = Fuel-specific default CO_2 emission factor, from Table C–1 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(ii) The minimum required sampling frequency for determining the annual average HHV (*e.g.*, monthly, quarterly, semi-annually, or by lot) is specified in § 98.34. The method for computing the annual average HHV is a function of unit size and how frequently you perform or receive from the fuel supplier the results of fuel sampling for HHV. The method is specified in paragraph (a)(2)(ii)(A) or (a)(2)(ii)(B) of this section, as applicable.

(A) If the results of fuel sampling are received monthly or more frequently, then for each unit with a maximum rated heat input capacity greater than or equal to 100 mmBtu/hr (or for a group of units that includes at least one unit of that size), the annual average HHV shall be calculated using Equation C–2b of this section. If multiple HHV determinations are made in any month, average the values for the month arithmetically.

$$(HHV)_{annual} = \frac{\sum_{i=1}^{n}(HHV)_i * (Fuel)_i}{\sum_{i=1}^{n}(Fuel)_i} \qquad \text{(Eq. C-2b)}$$

Where:

$(HHV)_{annual}$ = Weighted annual average high heat value of the fuel (mmBtu per mass or volume).

$(HHV)_I$ = Measured high heat value of the fuel, for month "i" (which may be the arithmetic average of multiple determinations), or, if applicable, an appropriate substitute data value (mmBtu per mass or volume).

$(Fuel)_I$ = Mass or volume of the fuel combusted during month "i," from company records (express mass in short tons for solid fuel, volume in standard cubic feet for gaseous fuel, and volume in gallons for liquid fuel).

n = Number of months in the year that the fuel is burned in the unit.

(B) If the results of fuel sampling are received less frequently than monthly, or, for a unit with a maximum rated heat input capacity less than 100 mmBtu/hr (or a group of such units) regardless of the HHV sampling frequency, the annual average HHV shall either be computed according to paragraph (a)(2)(ii)(A) of this section or as the arithmetic average HHV for all values for the year (including valid samples and substitute data values under § 98.35).

(iii) For units that combust municipal solid waste (MSW) and that produce steam, use Equation C–2c of this section. Equation C–2c of this section may also be used for any other solid fuel listed in Table C–1 of this subpart provided that steam is generated by the unit.

$$CO_2 = 1 \text{ x } 10^{-3} \text{ Steam} * B * EF \qquad \text{(Eq. C-2c)}$$

Where:

CO_2 = Annual CO_2 mass emissions from MSW or solid fuel combustion (metric tons).

Steam = Total mass of steam generated by MSW or solid fuel combustion during the reporting year (lb steam).

B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output capacity (mmBtu/lb steam).

EF = Fuel-specific default CO_2 emission factor, from Table C–1 of this subpart (kg CO_2/mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) *Tier 3 Calculation Methodology.* Calculate the annual CO_2 mass emissions for each fuel by using either Equation C3, C4, or C5 of this section, as appropriate.

(i) For a solid fuel, use Equation C–3 of this section.

$$CO_2 = \frac{44}{12} * \text{Fuel} * \text{CC} * 0.91 \qquad \text{(Eq. C-3)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific solid fuel (metric tons).

Fuel = Annual mass of the solid fuel combusted, from company records as defined in § 98.6 (short tons).

CC = Annual average carbon content of the solid fuel (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.91 = Conversion factor from short tons to metric tons.

(ii) For a liquid fuel, use Equation C–4 of this section.

$$CO_2 = \frac{44}{12} * \text{Fuel} * \text{CC} * 0.001 \qquad \text{(Eq. C-4)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the combustion of the specific liquid fuel (metric tons).

Fuel = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to § 98.3(i). Fuel billing meters may be used for this purpose. Tank drop measurements may also be used.

CC = Annual average carbon content of the liquid fuel (kg C per gallon of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(iii) For a gaseous fuel, use Equation C–5 of this section.

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 \qquad \text{(Eq. C-5)}$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of the specific gaseous fuel (metric tons).

Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to § 98.3(i). Fuel billing meters may be used for this purpose.

CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedures as specified for HHV in paragraph (a)(2)(ii) of this section.

MVC = Molar volume conversion factor at standard conditions, as defined in § 98.6.

Use 849.5 scf per kg mole if you select 68 °F as standard temperature and 836.6 scf per kg mole if you select 60 °F as standard temperature.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(iv) Fuel flow meters that measure mass flow rates may be used for liquid or gaseous fuels, provided that the fuel density is used to convert the readings to volumetric flow rates. The density shall be measured at the same frequency as the carbon content. You must measure the density using one of the following appropriate methods. You may use a method published by a consensus-based standards organization, if such a method exists, or you may use industry standard practice. 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*). The method(s) used shall be documented in the GHG Monitoring Plan required under §98.3(g)(5).

(v) The following default density values may be used for fuel oil, in lieu of using the methods in paragraph (a)(3)(iv) of this section: 6.8 lb/gal for No. 1 oil; 7.2 lb/gal for No. 2 oil; 8.1 lb/gal for No. 6 oil.

(4) *Tier 4 Calculation Methodology.* Calculate the annual CO_2 mass emissions from all fuels combusted in a unit, by using quality-assured data from continuous emission monitoring systems (CEMS).

(i) This methodology requires a CO_2 concentration monitor and a stack gas volumetric flow rate monitor, except as otherwise provided in paragraph (a)(4)(iv) of this section. Hourly measurements of CO_2 concentration and stack gas flow rate are converted to CO_2 mass emission rates in metric tons per hour.

(ii) When the CO_2 concentration is measured on a wet basis, Equation C–6 of this section is used to calculate the hourly CO_2 emission rates:

$$CO_2 = 5.18\,x\,10^{-7} * C_{CO2} * Q \quad \text{(Eq. C-6)}$$

Where:

CO_2 = CO_2 mass emission rate (metric tons/hr).

C_{CO2} = Hourly average CO_2 concentration (% CO_2).

Q = Hourly average stack gas volumetric flow rate (scfh).

5.18×10^{-7} = Conversion factor (metric tons/scf/% CO_2).

(iii) If the CO_2 concentration is measured on a dry basis, a correction for the stack gas moisture content is required. You shall either continuously monitor the stack gas moisture content using a method described in §75.11(b)(2) of this chapter or use an appropriate default moisture percentage. For coal, wood, and natural gas combustion, you may use the default moisture values specified in §75.11(b)(1) of this chapter. Alternatively, for any type of fuel, you may determine an appropriate site-specific default moisture value (or values), using measurements made with EPA Method 4—Determination Of Moisture Content In Stack Gases, in appendix A–3 to part 60 of this chapter. Moisture data from the relative accuracy test audit (RATA) of a CEMS may be used for this purpose. If this option is selected, the site-specific moisture default value(s) must represent the fuel(s) or fuel blends that are combusted in the unit during normal, stable operation, and must account for any distinct difference(s) in the stack gas moisture content associated with different process operating conditions. For each site-specific default moisture percentage, at least nine Method 4 runs are required, except where the option to use moisture data from a RATA is selected, and the applicable regulation allows a single moisture determination to represent two or more RATA runs. In that case, you may base the site-specific moisture percentage on the number of moisture runs allowed by the RATA regulation. Calculate each site-specific default moisture value by taking the arithmetic average of the Method 4 runs. Each site-specific moisture default value shall be updated whenever the owner or operator believes the current value is non-representative, due to changes in unit or process operation, but in any event no less frequently than annually. Use the updated moisture value in the subsequent CO_2 emissions calculations. For each unit operating hour, a moisture correction must be applied to Equation C–6 of this section as follows:

$$CO_2^* = CO_2\left(\frac{100 - \%H_2O}{100}\right) \qquad \text{(Eq. C-7)}$$

where:

CO_2* = Hourly CO_2 mass emission rate, corrected for moisture (metric tons/hr).

CO_2 = Hourly CO_2 mass emission rate from Equation C–6 of this section, uncorrected (metric tons/hr).

%H_2O = Hourly moisture percentage in the stack gas (measured or default value, as appropriate).

(iv) An oxygen (O_2) concentration monitor may be used in lieu of a CO_2 concentration monitor to determine the hourly CO_2 concentrations, in accordance with Equation F–14a or F–14b (as applicable) in appendix F to part 75 of this chapter, if the effluent gas stream monitored by the CEMS consists solely of combustion products (*i.e.*, no process CO_2 emissions or CO_2 emissions from sorbent are mixed with the combustion products) and if only fuels that are listed in Table 1 in section 3.3.5 of appendix F to part 75 of this chapter are combusted in the unit. If the O_2 monitoring option is selected, the F-factors used in Equations F–14a and F–14b shall be determined according to section 3.3.5 or section 3.3.6 of appendix F to part 75 of this chapter, as applicable. If Equation F–14b is used, the hourly moisture percentage in the stack gas shall be determined in accordance with paragraph (a)(4)(iii) of this section.

(v) Each hourly CO_2 mass emission rate from Equation C–6 or C–7 of this section is multiplied by the operating time to convert it from metric tons per hour to metric tons. The operating time is the fraction of the hour during which fuel is combusted (e.g., the unit operating time is 1.0 if the unit operates for the whole hour and is 0.5 if the unit operates for 30 minutes in the hour). For common stack configurations, the operating time is the fraction of the hour during which effluent gases flow through the common stack.

(vi) The hourly CO_2 mass emissions are then summed over each calendar quarter and the quarterly totals are summed to determine the annual CO_2 mass emissions.

(vii) If both biomass and fossil fuel are combusted during the year, determine and report the biogenic CO_2 mass emissions separately, as described in paragraph (e) of this section.

(viii) If a portion of the flue gases generated by a unit subject to Tier 4 (*e.g.*, a slip stream) is continuously diverted from the main flue gas exhaust system for the purpose of heat recovery or some other similar process, and then exhausts through a stack that is not equipped with the continuous emission monitors to measure CO_2 mass emissions, CO_2 emissions shall be determined as follows:

(A) At least once a year, use EPA Methods 2 and 3A, and (if necessary) Method 4 in appendices A–2 and A–3 to part 60 of this chapter to perform emissions testing at a set point that best represents normal, stable process operating conditions. A minimum of three one-hour Method 3A tests are required, to determine the CO_2 concentration. A Method 2 test shall be performed during each Method 3A run, to determine the stack gas volumetric flow rate. If moisture correction is necessary, a

Method 4 run shall also be performed during each Method 3A run. Important parametric information related to the stack gas flow rate (*e.g.*, damper positions, fan settings, *etc.*) shall also be recorded during the test.

(B) Calculate a CO_2 mass emission rate (in metric tons/hr) from the stack test data, using a version of Equation C–6 in paragraph (a)(4)(ii) of this section, modified as follows. In the Equation C–6 nomenclature, replace the words "Hourly average" in the definitions of "C_{CO2}" and "Q" with the words "3-run average". Substitute the arithmetic average values of CO_2 concentration and stack gas flow rate from the emission testing into modified Equation C–6. If CO_2 is measured on a dry basis, a moisture correction of the calculated CO_2 mass emission rate is required. Use Equation C–7 in paragraph (a)(4)(ii) of this section to make this correction; replace the word "Hourly" with the words "3-run average" in the equation nomenclature.

(C) The results of each annual stack test shall be used in the GHG emissions calculations for the year of the test.

(D) If, for the majority of the operating hours during the year, the diverted stream is withdrawn at a steady rate at or near the tested set point (as evidenced by fan and damper settings and/or other parameters), you may use the calculated CO_2 mass emission rate from paragraph (a)(4)(viii)(B) of this section to estimate the CO_2 mass emissions for all operating hours in which flue gas is diverted from the main exhaust system. Otherwise, you must account for the variation in the flow rate of the diverted stream, as described in paragraph (c)(4)(viii)(E) of this section.

(E) If the flow rate of the diverted stream varies significantly throughout the year, except as provided below, repeat the stack test and emission rate calculation procedures described in paragraphs (c)(4)(viii)(A) and (c)(4)(viii)(B) of this section at a minimum of two more set points across the range of typical operating conditions to develop a correlation between CO_2 mass emission rate and the parametric data. If additional testing is not feasible, use the following approach to develop the necessary correlation. Assume that the average CO_2 concentration obtained in the annual stack test is the same at all operating set points. Then, beginning with the measured flow rate from the stack test and the associated parametric data, perform an engineering analysis to estimate the stack gas flow rate at two or more additional set points. Calculate the CO_2 mass emission rate at each set point.

(F) Calculate the annual CO_2 mass emissions for the diverted stream as follows. For a steady-state process, multiply the number of hours in which flue gas was diverted from the main exhaust system by the CO_2 mass emission rate from the stack test. Otherwise, using the best available information and engineering judgment, apply the most representative CO_2 mass emission rate from the correlation in paragraph (c)(4)(viii)(E) of this section to determine the CO_2 mass emissions for each hour in which flue gas was diverted, and sum the results. To simplify the calculations, you may count partial operating hours as full hours.

(G) Finally, add the CO_2 mass emissions from paragraph(c)(4)(viii)(F) of this section to the annual CO_2 mass emissions measured by the CEMS at the main stack. Report this sum as the total annual CO_2 mass emissions for the unit.

(H) The exact method and procedures used to estimate the CO_2 mass emissions for the diverted portion of the flue gas exhaust stream shall be documented in the Monitoring Plan required under §98.3(g)(5).

(5) *Alternative methods for certain units subject to Part 75 of this chapter*. Certain units that are not subject to subpart D of this part and that report data to EPA according to part 75 of this chapter may qualify to use the alternative methods in this paragraph (a)(5), in lieu of using any of the four calculation methodology tiers.

(i) For a unit that combusts only natural gas and/or fuel oil, is not subject to subpart D of this part, monitors and reports heat input data year-round according to appendix D to part 75 of this chapter, but is not required by the applicable part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions for the purposes of this part as follows:

(A) Use the hourly heat input data from appendix D to part 75 of this chapter, together with Equation G–4 in appendix G to part 75 of this chapter to determine the hourly CO_2 mass emission rates, in units of tons/hr;

(B) Use Equations F–12 and F–13 in appendix F to part 75 of this chapter to calculate the quarterly and cumulative annual CO_2 mass emissions, respectively, in units of short tons; and

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(ii) For a unit that combusts only natural gas and/or fuel oil, is not subject to subpart D of this part, monitors and reports heat input data year-round according to § 75.19 of this chapter but is not required by the applicable part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions for the purposes of this part as follows:

(A) Calculate the hourly CO_2 mass emissions, in units of short tons, using Equation LM–11 in § 75.19(c)(4)(iii) of this chapter.

(B) Sum the hourly CO_2 mass emissions values over the entire reporting year to obtain the cumulative annual CO_2 mass emissions, in units of short tons.

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(iii) For a unit that is not subject to subpart D of this part, uses flow rate and CO_2 (or O_2) CEMS to report heat input data year-round according to part 75 of this chapter, but is not required by the applicable part 75 program to report CO_2 mass emissions data, calculate the annual CO_2 mass emissions as follows:

(A) Use Equation F–11 or F–2 (as applicable) in appendix F to part 75 of this chapter to calculate the hourly CO_2 mass emission rates from the CEMS data. If an O_2 monitor is used, convert the hourly average O_2 readings to CO_2 using Equation F–14a or F–14b in appendix F to part 75 of this chapter (as applicable), before applying Equation F–11 or F–2.

(B) Use Equations F–12 and F–13 in appendix F to part 75 of this chapter to calculate the quarterly and cumulative annual CO_2 mass emissions, respectively, in units of short tons.

(C) Divide the cumulative annual CO_2 mass emissions value by 1.1 to convert it to metric tons.

(iv) For units that qualify to use the alternative CO_2 emissions calculation methods in paragraphs (a)(5)(i) through (a)(5)(iii) of this section, if both biomass and fossil fuel are combusted during the year, separate calculation and reporting of the biogenic CO_2 mass emissions (as described in paragraph (e) of this section) is optional, only for the 2010 reporting year, as provided in § 98.3(c)(12).

(b) *Use of the four tiers.* Use of the four tiers of CO_2 emissions calculation methodologies described in paragraph (a) of this section is subject to the following conditions, requirements, and restrictions:

(1) The Tier 1 Calculation Methodology:

(i) May be used for any fuel listed in Table C–1 of this subpart that is combusted in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less.

(ii) May be used for MSW in a unit of any size that does not produce steam, if the use of Tier 4 is not required.

(iii) May be used for solid, gaseous, or liquid biomass fuels in a unit of any size provided that the fuel is listed in Table C–1 of this subpart.

(iv) May not be used if you routinely perform fuel sampling and analysis for the fuel high heat value (HHV) or routinely receive the results of HHV sampling and analysis from the fuel supplier at the minimum frequency specified in § 98.34(a), or at a greater frequency. In such cases, Tier 2 shall be used. This restriction does not apply to paragraphs (b)(1)(ii), (b)(1)(v), (b)(1)(vi), and (b)(1)(vii) of this section.

(v) May be used for natural gas combustion in a unit of any size, in cases where the annual natural gas consumption is obtained from fuel billing records in units of therms or mmBtu.

(vi) May be used for MSW combustion in a small, batch incinerator that burns no more than 1,000 tons per year of MSW.

(vii) May be used for the combustion of MSW and/or tires in a unit, provided that no more than 10 percent of the unit's annual heat input is derived from those fuels, combined. Notwithstanding this requirement, if a unit combusts both MSW and tires and the reporter elects not to separately calculate and report biogenic CO_2 emissions from the combustion of tires, Tier 1 may be used for the MSW combustion, provided that no more than 10 percent of the unit's annual heat input is derived from MSW.

(viii) May be used for the combustion of a fuel listed in Table C–1 if the fuel is combusted in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr (or, pursuant to §98.36(c)(3), in a group of units served by a common supply pipe, having at least one unit with a maximum rated heat input capacity greater than 250 mmBtu/hr), provided that both of the following conditions apply:

(A) The use of Tier 4 is not required.

(B) The fuel provides less than 10 percent of the annual heat input to the unit, or if §98.36(c)(3) applies, to the group of units served by a common supply pipe.

(2) The Tier 2 Calculation Methodology:

(i) May be used for the combustion of any type of fuel in a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less provided that the fuel is listed in Table C–1 of this subpart.

(ii) May be used in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr for the combustion of natural gas and/or distillate fuel oil.

(iii) May be used for MSW in a unit of any size that produces steam, if the use of Tier 4 is not required.

(3) The Tier 3 Calculation Methodology:

(i) May be used for a unit of any size that combusts any type of fuel listed in Table C–1 of this subpart (except for MSW), unless the use of Tier 4 is required.

(ii) Shall be used for a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr that combusts any type of fuel listed in Table C–1 of this subpart (except MSW), unless either of the following conditions apply:

(A) The use of Tier 1 or 2 is permitted, as described in paragraphs (b)(1)(iii), (b)(1)(v), (b)(1)(viii), and (b)(2)(ii) of this section.

(B) The use of Tier 4 is required.

(iii) Shall be used for a fuel not listed in Table C–1 of this subpart if the fuel is combusted in a unit with a maximum rated heat input capacity greater than 250 mmBtu/hr (or, pursuant to §98.36(c)(3), in a group of units served by a common supply pipe, having at least one unit with a maximum rated heat input capacity greater than 250 mmBtu/hr), provided that both of the following conditions apply:

(A) The use of Tier 4 is not required.

(B) The fuel provides 10% or more of the annual heat input to the unit or, if §98.36(c)(3) applies, to the group of units served by a common supply pipe.

(iv) Shall be used when specified in another applicable subpart of this part, regardless of unit size.

(4) The Tier 4 Calculation Methodology:

(i) May be used for a unit of any size, combusting any type of fuel. Tier 4 may also be used for any group of stationary fuel combustion units, process units, or manufacturing units that share a common stack or duct.

(ii) Shall be used if the unit meets all six of the conditions specified in paragraphs (b)(4)(ii)(A) through (b)(4)(ii)(F) of this section:

(A) The unit has a maximum rated heat input capacity greater than 250 mmBtu/hr, or if the unit combusts municipal solid waste and has a maximum rated input capacity greater than 600 tons per day of MSW.

(B) The unit combusts solid fossil fuel or MSW as the primary fuel.

(C) The unit has operated for more than 1,000 hours in any calendar year since 2005.

(D) The unit has installed CEMS that are required either by an applicable Federal or State regulation or the unit's operating permit.

(E) The installed CEMS include a gas monitor of any kind or a stack gas volumetric flow rate monitor, or both and the monitors have been certified, either in accordance with the requirements of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program.

(F) The installed gas or stack gas volumetric flow rate monitors are required, either by an applicable Federal or State regulation or by the unit's operating permit, to undergo periodic quality assurance testing in accordance with either appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program.

(iii) Shall be used for a unit with a maximum rated heat input capacity of 250 mmBtu/hr or less and for a unit that combusts municipal solid waste with a maximum rated input capacity of 600 tons of MSW per day or less, if the unit meets all of the following three conditions:

(A) The unit has both a stack gas volumetric flow rate monitor and a CO_2 concentration monitor.

(B) The unit meets the conditions specified in paragraphs (b)(4)(ii)(B) through (b)(4)(ii)(D) of this section.

(C) The CO_2 and stack gas volumetric flow rate monitors meet the conditions specified in paragraphs (b)(4)(ii)(E) and (b)(4)(ii)(F) of this section.

(iv) May apply to common stack or duct configurations where:

(A) The combined effluent gas streams from two or more stationary fuel combustion units are vented through a monitored common stack or duct. In this case, Tier 4 shall be used if all of the conditions in paragraph (b)(4)(iv)(A)(1) of this section or if the conditions in paragraph (b)(4)(iv)(A)(2) of this section are met.

(*1*) At least one of the units meets the requirements of paragraphs (b)(4)(ii)(A) through (b)(4)(ii)(C) of this section, and the CEMS installed at the common stack (or duct) meet the requirements of paragraphs (b)(4)(ii)(D) through (b)(4)(ii)(F) of this section.

(*2*) At least one of the units and the monitors installed at the common stack or duct meet the requirements of paragraph (b)(4)(iii) of this section.

(B) The combined effluent gas streams from a process or manufacturing unit and a stationary fuel combustion unit are vented through a monitored common stack or duct. In this case, Tier 4 shall be used if the combustion unit and the monitors installed at the common stack or duct meet the applicability criteria specified in paragraph (b)(4)(iv)(A)(*1*), or (b)(4)(iv)(A)(*2*) of this section.

(C) The combined effluent gas streams from two or more manufacturing or process units are vented through a common stack or duct. In this case, if any of the units is required by an applicable subpart of this part to use Tier 4, the CO_2 mass emissions may be monitored at each individual unit, or the combined CO_2 mass emissions may be monitored at the common stack or duct. However, if it is not feasible to monitor the individual units, the combined CO_2 mass emissions shall be monitored at the common stack or duct.

(5) The Tier 4 Calculation Methodology shall be used:

(i) Starting on January 1, 2010, for a unit that is required to report CO_2 mass emissions beginning on that date, if all of the monitors needed to measure CO_2 mass emissions have been installed and certified by that date.

(ii) No later than January 1, 2011, for a unit that is required to report CO_2 mass emissions beginning on January 1, 2010, if all of the monitors needed to measure CO_2 mass emissions have not been installed and certified by January 1, 2010. In this case, you may use Tier 2 or Tier 3 to report GHG emissions for 2010. However, if the required CEMS are certified some time in 2010, you need not wait until January 1, 2011 to begin using Tier 4. Rather, you may switch from Tier 2 or Tier 3 to Tier 4 as soon as CEMS certification testing is successfully completed. If this reporting option is chosen, you must document the change in CO_2 calculation methodology in the Monitoring Plan required under § 98.3(g)(5) and in the GHG emissions report under § 98.3(c). Data recorded by the CEMS during a certification test period in 2010 may be used for reporting under this part, provided that the following two conditions are met:

(A) The certification tests are passed in sequence, with no test failures.

(B) No unscheduled maintenance or repair of the CEMS is performed during the certification test period.

(iii) No later than 180 days following the date on which a change is made that triggers Tier 4 applicability under paragraph (b)(4)(ii) or (b)(4)(iii) of this section (*e.g.*, a change in the primary fuel, manner of unit operation, or installed continuous monitoring equipment).

(6) You may elect to use any applicable higher tier for one or more of the fuels combusted in a unit. For example, if a 100 mmBtu/hr unit combusts natural gas and distillate fuel oil, you may elect to use Tier 1 for natural gas and Tier 3 for the fuel oil, even though Tier 1 could have been used for both fuels. However, for units that use either the Tier 4 or the alternative calculation methodology specified in paragraph (a)(5)(iii) of this section, CO_2 emissions from the combustion of all fuels shall be based solely on CEMS measurements.

(c) *Calculation of CH_4 and N_2O emissions from stationary combustion sources.* You must calculate annual CH_4 and N_2O mass emissions only for units that are required to report CO_2 emissions using the calculation methodologies of this subpart and for only those fuels that are listed in Table C–2 of this subpart.

(1) Use Equation C–8 of this section to estimate CH_4 and N_2O emissions for any fuels for which you use the Tier 1 or Tier 3 calculation methodologies for CO_2, except when natural gas usage in units of therms or mmBtu is obtained from gas billing records. In that case, use Equation C–8a in paragraph (c)(1)(i) of this section or Equation C–8b in paragraph (c)(1)(ii) of this section (as applicable). For Equation C–8, use the same values for fuel consumption that you use for the Tier 1 or Tier 3 calculation.

$$CH_4 \text{ or } N_2O = 1\,x\,10^{-3} * Fuel * HHV * EF \qquad \text{(Eq. C-8)}$$

Where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).

Fuel = Mass or volume of the fuel combusted, either from company records or directly measured by a fuel flow meter, as applicable (mass or volume per year).

HHV = Default high heat value of the fuel from Table C–1 of this subpart; alternatively, for Tier 3, if actual HHV data are available for the reporting year, you may average these data using the procedures specified in paragraph (a)(2)(ii) of this section, and use the average value in Equation C–8 (mmBtu per mass or volume).

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons.

(i) Use Equation C–8a to calculate CH_4 and N_2O emissions when natural gas usage is obtained from gas billing records in units of therms.

$$CH_4 \text{ or } N_2O = 1\,x\,10^{-3} * Fuel * 0.1 * EF \qquad \text{(Eq. C-8a)}$$

where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of natural gas (metric tons).

Fuel = Annual natural gas usage, from gas billing records (therms).

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu).

0.1 = Conversion factor from therms to mmBtu

1×10^{-3} = Conversion factor from kilograms to metric tons.

(ii) Use Equation C–8b to calculate CH_4 and N_2O emissions when natural gas usage is obtained from gas billing records in units of mmBtu.

CH_4 or N_2O = $1 \times 10^{-3} * Fuel * EF$ (Eq. C–8b)

where:

CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of natural gas (metric tons).

Fuel = Annual natural gas usage, from gas billing records (mmBtu).

EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu).
1×10^{-3} = Conversion factor from kilograms to metric tons.

(2) Use Equation C–9a of this section to estimate CH_4 and N_2O emissions for any fuels for which you use the Tier 2 Equation C–2a of this section to estimate CO_2 emissions. Use the same values for fuel consumption and HHV that you use for the Tier 2 calculation.

$$CH_4 \text{ or } N_2O = 1 \text{ x } 10^{-3} * HHV * EF * Fuel \qquad \text{(Eq. C-9a)}$$

Where:
CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).
Fuel = Mass or volume of the fuel combusted during the reporting year.
HHV = High heat value of the fuel, averaged for all valid measurements for the reporting year (mmBtu per mass or volume).
EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu).
1×10^{-3} = Conversion factor from kilograms to metric tons.

(3) Use Equation C–9b of this section to estimate CH_4 and N_2O emissions for any fuels for which you use Equation C–2c of this section to calculate the CO_2 emissions. Use the same values for steam generation and the ratio ‘‘B’’ that you use for Equation C–2c.

$$CH_4 \text{ or } N_2O = 1 \text{ x } 10^{-3} \text{ Steam} * B * EF \qquad \text{(Eq. C-9b)}$$

Where:
CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a solid fuel (metric tons).
Steam = Total mass of steam generated by solid fuel combustion during the reporting year (lb steam).
B = Ratio of the boiler's maximum rated heat input capacity to its design rated steam output (mmBtu/lb steam).
EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu).
1×10^{-3} = Conversion factor from kilograms to metric tons.

(4) Use Equation C–10 of this section for: units subject to subpart D of this part; units that qualify for and elect to use the alternative CO_2 mass emissions calculation methodologies described in paragraph (a)(5) of this section; and units that use the Tier 4 Calculation Methodology.

$$CH_4 \text{ or } N_2O = 0.001 * (HI)_A * EF \qquad \text{(Eq. C-10)}$$

Where:
CH_4 or N_2O = Annual CH_4 or N_2O emissions from the combustion of a particular type of fuel (metric tons).
$(HI)_A$ = Cumulative annual heat input from combustion of the fuel (mmBtu).
EF = Fuel-specific emission factor for CH_4 or N_2O, from Table C–2 of this section (kg CH_4 or N_2O per mmBtu).
0.001 = Conversion factor from kg to metric tons.

(i) If only one type of fuel listed in Table C–2 of this subpart is combusted during the reporting year, substitute the cumulative annual heat input from combustion of the fuel into Equation C–10 of this section to calculate the annual CH_4 or N_2O emissions. For units in the Acid Rain Program and units that report heat input data to EPA year-round according to part 75 of this chapter, obtain the cumulative annual heat input directly from the electronic data reports required under §75.64 of this chapter. For Tier 4 units, use the best available information, as described in paragraph (c)(4)(ii)(C) of this section, to estimate the cumulative annual heat input $(HI)_A$.

(ii) If more than one type of fuel listed in Table C–2 of this subpart is combusted during the reporting year, use Equation C–10 of this section separately for each type of fuel, except as provided in paragraph (c)(4)(ii)(B) of this section. Determine the appropriate values of $(HI)_A$ as follows:

(A) For units in the Acid Rain Program and other units that report heat input data to EPA year-round according to part 75 of this chapter, obtain $(HI)_A$ for each type of fuel from the electronic data reports required under §75.64 of this chapter, except as otherwise provided in paragraphs (c)(4)(ii)(B) and (c)(4)(ii)(D) of this section.

(B) For a unit that uses CEMS to monitor hourly heat input according to part 75 of this chapter, the value of $(HI)_A$ obtained from the electronic data reports under §75.64 of this chapter may be attributed exclusively to the fuel with the highest F-factor, when the reporting option in 3.3.6.5 of appendix F to part 75 of this chapter is selected and implemented.

(C) For Tier 4 units, use the best available information (*e.g.*, fuel feed rate measurements, fuel heating values, engineering analysis) to estimate the value of $(HI)_A$ for each type of fuel. Instrumentation used to make these estimates is not subject to the calibration requirements of §98.3(i) or to the QA requirements of §98.34.

(D) Units in the Acid Rain Program and other units that report heat input data to EPA year-round according to part 75 of this chapter may use the best available information described in paragraph (c)(4)(ii)(C) of this section, to estimate $(HI)_A$ for each fuel type, whenever fuel-specific heat input values cannot be directly obtained from the electronic data reports under §75.64 of this chapter.

(5) When multiple fuels are combusted during the reporting year, sum the fuel-specific results from Equations C–8, C–8a, C–8b, C–9a, C–9b, or C–10 of this section (as applicable) to obtain the total annual CH_4 and N_2O emissions, in metric tons.

(6) Calculate the annual CH_4 and N_2O mass emissions from the combustion of blended fuels as follows:

(i) If the mass or volume of each component fuel in the blend is measured before the fuels are mixed and combusted, calculate and report CH_4 and N_2O emissions separately for each component fuel, using the applicable procedures in this paragraph (c).

(ii) If the mass or volume of each component fuel in the blend is not measured before the fuels are mixed and combusted, a reasonable estimate of the percentage composition of the blend, based on best available information, is required. Perform the following calculations for each component fuel "i" that is listed in Table C–2:

(A) Multiply $(\% \text{ Fuel})_i$, the estimated mass or volume percentage (decimal fraction) of component fuel "i", by the total annual mass or volume of the blended fuel combusted during the reporting year, to obtain an estimate of the annual consumption of component "i";

(B) Multiply the result from paragraph (c)(6)(ii)(A) of this section by the HHV of the fuel (default value or, if available, the measured annual average value), to obtain an estimate of the annual heat input from component "i";

(C) Calculate the annual CH_4 and N_2O emissions from component "i", using Equation C–8, C–8a, C–8b, C–9a, or C–10 of this section, as applicable;

(D) Sum the annual CH_4 emissions across all component fuels to obtain the annual CH_4 emissions for the blend. Similarly sum the annual N_2O emissions across all component fuels to obtain the annual N_2O emissions for the blend. Report these annual emissions totals.

(d) *Calculation of CO_2 from sorbent.* (1) When a unit is a fluidized bed boiler, is equipped with a wet flue gas desulfurization system, or uses other acid gas emission controls with sorbent injection to remove acid gases, if the chemical reaction between the acid gas and the sorbent produces CO_2 emissions, use Equation C–11 of this section to calculate the CO_2 emissions from the sorbent, except when those CO_2 emissions are monitored by CEMS. When a sorbent other than $CaCO_3$ is used, determine site-specific values of R and MW_S.

$$CO_2 = 0.91 * S * R * \left(\frac{MW_{CO2}}{MW_S} \right) \qquad \text{(Eq. C-11)}$$

Where:

CO_2 = CO_2 emitted from sorbent for the reporting year (metric tons).

S = Limestone or other sorbent used in the reporting year, from company records (short tons).

R = The number of moles of CO_2 released upon capture of one mole of the acid gas species being removed (R = 1.00 when the sorbent is $CaCO_3$ and the targeted acid gas species is SO_2).

MW_{CO2} = Molecular weight of carbon dioxide (44).

MW_S = Molecular weight of sorbent (100 if calcium carbonate).

0.91 = Conversion factor from short tons to metric tons.

(2) The total annual CO_2 mass emissions reported for the unit shall include the CO_2 emissions from the combustion process and the CO_2 emissions from the sorbent.

(e) *Biogenic CO_2 emissions from combustion of biomass with other fuels.* Use the applicable procedures of this paragraph (e) to estimate biogenic CO_2 emissions from units that combust a combination of biomass and fossil fuels (*i.e.,* either co-fired or blended fuels). Separate reporting of biogenic CO_2 emissions from the combined combustion of biomass and fossil fuels is required for those biomass fuels listed in Table C–1 of this section and for municipal solid waste. In addition, when a biomass fuel that is not listed in Table C–1 is combusted in a unit that has a maximum rated heat input greater than 250 mmBtu/hr, if the biomass fuel accounts for 10% or more of the annual heat input to the unit, and if the unit does not use CEMS to quantify its annual CO_2 mass emissions, then, pursuant to § 98.33(b)(3)(iii), Tier 3 must be used to determine the carbon content of the biomass fuel and to calculate the biogenic CO_2 emissions from combustion of the fuel. Notwithstanding these requirements, in accordance with § 98.3(c)(12), separate reporting of biogenic CO_2 emissions is optional for the 2010 reporting year for units subject to subpart D of this part and for units that use the CO_2 mass emissions calculation methodologies in part 75 of this chapter, pursuant to paragraph (a)(5) of this section. However, if the owner or operator opts to report biogenic CO_2 emissions separately for these units, the appropriate method(s) in this paragraph (e) shall be used. Separate reporting of biogenic CO_2 emissions from the combustion of tires is also optional, but may be reported by following the provisions of paragraph (e)(3) of this section.

(1) You may use Equation C–1 of this subpart to calculate the annual CO_2 mass emissions from the combustion of the biomass fuels listed in Table C–1 of this subpart (except MSW and tires), in a unit of any size, including units equipped with a CO_2 CEMS, except when the use of Tier 2 is required as specified in paragraph (b)(1)(iv) of this section. Determine the quantity of biomass combusted using one of the following procedures in this paragraph (e)(1), as appropriate, and document the selected procedures in the Monitoring Plan under § 98.3(g):

(i) Company records.

(ii) The procedures in paragraph (e)(4) of this section.

(iii) The best available information for premixed fuels that contain biomass and fossil fuels (*e.g.,* liquid fuel mixtures containing biodiesel).

(2) You may use the procedures of this paragraph if the following three conditions are met: First, a CO_2 CEMS (or a surrogate O_2 monitor) and a stack gas flow rate monitor are used to determine the annual CO_2 mass emissions (either according to part 75 of this

chapter, the Tier 4 Calculation Methodology, or the alternative calculation methodology specified in paragraph (a)(5)(iii) of this section); second, neither MSW nor tires is combusted in the unit during the reporting year; and third, the CO_2 emissions consist solely of combustion products (*i.e.*, no process or sorbent emissions included).

(i) For each operating hour, use Equation C–12 of this section to determine the volume of CO_2 emitted.

$$V_{CO2h} = \frac{(\%CO_2)_h}{100} * Q_h * t_h \qquad \text{(Eq. C-12)}$$

Where:

V_{CO2h} = Hourly volume of CO_2 emitted (scf).

$(\%CO_2)_h$ = Hourly average CO_2 concentration, measured by the CO_2 concentration monitor, or, if applicable, calculated from the hourly average O_2 concentration ($\%CO_2$).

Q_h = Hourly average stack gas volumetric flow rate, measured by the stack gas volumetric flow rate monitor (scfh).

t_h = Source operating time (decimal fraction of the hour during which the source combusts fuel, i.e., 1.0 for a full operating hour, 0.5 for 30 minutes of operation, etc.).

100 = Conversion factor from percent to a decimal fraction.

(ii) Sum all of the hourly V_{CO2h} values for the reporting year, to obtain V_{total}, the total annual volume of CO_2 emitted.

(iii) Calculate the annual volume of CO_2 emitted from fossil fuel combustion using Equation C–13 of this section. If two or more types of fossil fuel are combusted during the year, perform a separate calculation with Equation C–13 of this section for each fuel and sum the results.

$$V_{ff} = \frac{Fuel * F_c * HHV}{10^6} \qquad \text{(Eq. C-13)}$$

Where:

V_{ff} = Annual volume of CO_2 emitted from combustion of a particular fossil fuel (scf).

Fuel = Total quantity of the fossil fuel combusted in the reporting year, from company records, as defined in § 98.6 (lb for solid fuel, gallons for liquid fuel, and scf for gaseous fuel).

F_c = Fuel-specific carbon based F-factor, either a default value from Table 1 in section 3.3.5 of appendix F to part 75 of this chapter, or a site-specific value determined under section 3.3.6 of appendix F to part 75 (scf CO_2/mmBtu).

HHV = High heat value of the fossil fuel, from fuel sampling and analysis (annual average value in Btu/lb for solid fuel, Btu/gal for liquid fuel and Btu/scf for gaseous fuel, sampled as specified (e.g., monthly, quarterly, semi-annually, or by lot) in § 98.34(a)(2)). The average HHV shall be calculated according to the requirements of paragraph (a)(2)(ii) of this section.

10^6 = Conversion factor, Btu per mmBtu.

(iv) Subtract V_{ff} from V_{total} to obtain V_{bio}, the annual volume of CO_2 from the combustion of biomass.

(v) Calculate the biogenic percentage of the annual CO_2 emissions,expressed as a decimal fraction, using Equation C–14 of this section:

$$\%\,Biogenic = \frac{V_{bio}}{V_{total}} \qquad \text{(Eq. C-14)}$$

(vi) Calculate the annual biogenic CO_2 mass emissions, in metric tons, by multiplying the results obtained from Equation C–14 of this section by the annual CO_2 mass emissions in metric tons, as determined:

(A) Under paragraph (a)(4)(vi) of this section, for units using the Tier 4 Calculation Methodology.

(B) Under paragraph (a)(5)(iii)(B) of this section, for units using the alternative calculation methodology specified in paragraph (a)(5)(iii).

(C) From the electronic data report required under § 75.64 of this chapter, for units in the Acid Rain Program and other units using CEMS to monitor and report CO_2 mass emissions according to part 75 of this chapter. However, before calculating the annual biogenic CO_2 mass emissions, multiply the cumulative annual CO_2 mass emissions by 0.91 to convert from short tons to metric tons.

(3) You must use the procedures in paragraphs (e)(3)(i) through (e)(3)(iii) of this section to determine the annual biogenic CO_2 emissions from the combustion of MSW, except as otherwise provided in paragraph (e)(3)(iv) of this section. These procedures also may be used for any unit that co-fires biomass and fossil fuels, including units equipped with a CO_2 CEMS, and units for which optional separate reporting of biogenic CO_2 emissions from the combustion of tires is selected.

(i) Use an applicable CO_2 emissions calculation method in this section to quantify the total annual CO_2 mass emissions from the unit.

(ii) Determine the relative proportions of biogenic and non-biogenic CO_2 emissions in the flue gas on a quarterly basis using the method specified in § 98.34(d) (for units that combust MSW as the primary fuel or as the only fuel with a biogenic component) or in § 98.34(e) (for other units, including units that combust tires).

(iii) Determine the annual biogenic CO_2 mass emissions from the unit by multiplying the total annual CO_2 mass emissions by the annual average biogenic decimal fraction obtained from § 98.34(d) or § 98.34(e), as applicable.

(iv) If the combustion of MSW and/or tires provides no more than 10 percent of the annual heat input to a unit, or if a small, batch incinerator combusts no more than 1,000 tons per year of MSW, you may estimate the annual biogenic CO_2 emissions as follows, in lieu of following the procedures in paragraphs (e)(3)(i) through (e)(3)(iii) of this section:

(A) Calculate the total annual CO_2 emissions from combustion of MSW and/or tires in the unit, using the Tier 1 calculation methodology in paragraph (a)(1) of this section.

(B) Multiply the result from paragraph (e)(3)(iv)(A) of this section by the appropriate default factor to determine the annual biogenic CO_2 emissions, in metric tons. For MSW, use a default factor of 0.60 and for tires, use a default factor of 0.20.

(4) If Equation C–1 or Equation C–2a of this section is selected to calculate the annual biogenic mass emissions for wood, wood waste, or other solid biomass-derived fuel, Equation C–15 of this section may be used to quantify biogenic fuel consumption, provided that all of the required input parameters are accurately quantified. Similar equations and calculation methodologies based on steam generation and boiler efficiency may be used, provided that they are documented in the GHG Monitoring Plan required by § 98.3(g)(5).

$$(Fuel)_p = \frac{[H * S] - (HI)_{nb}}{2000\,(HHV)_{bio}\,(Eff)_{bio}} \qquad \text{(Eq. C-15)}$$

Where:

$(Fuel)_p$ = Quantity of biomass consumed during the measurement period "p" (tons/year or tons/month, as applicable).

H = Average enthalpy of the boiler steam for the measurement period (Btu/lb).

S = Total boiler steam production for the measurement period (lb/month or lb/year, as applicable).

$(HI)_{nb}$ = Heat input from co-fired fossil fuels and non-biomass-derived fuels for the measurement period, based on company records of fuel usage and default or measured HHV values (Btu/month or Btu/year, as applicable).

$(HHV)_{bio}$ = Default or measured high heat value of the biomass fuel (Btu/lb).

$(Eff)_{bio}$ = Percent efficiency of biomass-to-energy conversion, expressed as a decimal fraction.

2000 = Conversion factor (lb/ton).

(5) For units subject to subpart D of this part and for units that use the methods in part 75 of this chapter to quantify CO_2 mass emissions in accordance with paragraph (a)(5) of this section, you may calculate biogenic CO_2 emissions from the combustion of biomass fuels listed in Table C–1 of this subpart using Equation C–15a. This equation may not be used to calculate biogenic CO_2 emissions from the combustion of tires or MSW; the methods described in paragraph (e)(3) of this

section must be used for those fuels. Whenever $(HI)_A$, the annual heat input from combustion of biomass fuel in Equation C–15a, cannot be determined solely from the information in the electronic emissions reports under §75.64 of this chapter (*e.g.*, in cases where a unit uses CEMS in combination with multiple F-factors, a worst-case F-factor, or a prorated F-factor to report heat input rather than reporting heat input based on fuel type), use the best available information (as described in §§98.33(c)(4)(ii)(C) and (c)(4)(ii)(D)) to determine $(HI)_A$.

$$CO_2 = 0.001 * (HI)_A * EF \quad \text{(Eq. C–15a)}$$

where:

CO_2 = Annual CO_2 mass emissions from the combustion of a particular type of biomass fuel listed in Table C–1 (metric tons)

$(HI)_A$ = Annual heat input from the biomass fuel, obtained, where feasible, from the electronic emissions reports required under §75.64 of this chapter. Where this is not feasible use best available information, as described in §§98.33(c)(4)(ii)(C) and (c)(4)(ii)(D) (mmBtu)

EF = CO_2 emission factor for the biomass fuel, from Table C–1 (kg CO_2/mmBtu)

0.001 = Conversion factor from kg to metric tons

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§98.34 Monitoring and QA/QC requirements.

The CO_2 mass emissions data for stationary fuel combustion sources shall be monitored as follows:

(a) For the Tier 2 Calculation Methodology:

(1) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or the supplier of the fuel.

(2) The minimum required frequency of the HHV sampling and analysis for each type of fuel or fuel mixture (blend) is specified in this paragraph. When the specified frequency for a particular fuel or blend is based on a specified time period (*e.g.*, week, month, quarter, or half-year), fuel sampling and analysis is required only for those time periods in which the fuel or blend is combusted. The owner or operator may perform fuel sampling and analysis more often than the minimum required frequency, in order to obtain a more representative annual average HHV.

(i) For natural gas, semiannual sampling and analysis is required (*i.e.*, twice in a calendar year, with consecutive samples taken at least four months apart).

(ii) For coal and fuel oil, and for any other solid or liquid fuel that is delivered in lots, analysis of at least one representative sample from each fuel lot is required. For fuel oil, as an alternative to sampling each fuel lot, a sample may be taken upon each addition of oil to the unit's storage tank. Flow proportional sampling, continuous drip sampling, or daily manual oil sampling may also be used, in lieu of sampling each fuel lot. If the daily manual oil sampling option is selected, sampling from a particular tank is required only on days when oil from the tank is combusted by the unit (or units) served by the tank. If you elect to sample from the storage tank upon each addition of oil to the tank, you must take at least one sample from each tank that is currently in service and whenever oil is added to the tank, for as long as the tank remains in service. You need not take any samples from a storage tank while it is out of service. Rather, take a sample when the tank is brought into service and whenever oil is added to the tank, for as long as the tank remains in service. If multiple additions of oil are made to a particular in-service tank on a given day (*e.g.*, from multiple deliveries), one sample taken after the final addition of oil is sufficient. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single type of fuel (*e.g.*, ship load, barge load, group of trucks, group of railroad cars, oil delivery via pipeline from a tank farm, *etc.*). However, if multiple deliveries of a particular type of fuel are received from the same supply source in a given calendar month, the deliveries for that month may be considered, collectively, to comprise a fuel lot, requiring only one representative sample, subject to the following conditions:

(A) For coal, the ''type'' of fuel means the rank of the coal (*i.e.*, anthracite, bituminous, sub-bituminous, or lignite). For fuel oil, the ''type'' of fuel means the grade number or classification of the oil (*e.g.*, No. 1 oil, No. 2 oil, kerosene, Jet A fuel, *etc.*).

(B) The owner or operator shall document in the monitoring plan under § 98.3(g)(5) how the monthly sampling of each type of fuel is performed.

(iii) For liquid fuels other than fuel oil, and for gaseous fuels other than natural gas (including biogas), sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(iv) For other solid fuels (except MSW), weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(v) For fuel blends that are received already mixed, or that are mixed onsite without measuring the exact amount of each component, as described in paragraph (a)(3)(ii) of this section, determine the HHV of the blend as follows. For blends of solid fuels (except MSW), weekly sampling is required to obtain composite samples, which are analyzed monthly. For blends of liquid or gaseous fuels, sampling and analysis is required at least once per calendar quarter. More frequent sampling is recommended if the composition of the blend varies significantly during the year.

(3) *Special considerations for blending of fuels.* In situations where different types of fuel listed in Table C–1 of this subpart (for example, different ranks of coal or different grades of fuel oil) are in the same state of matter (*i.e.*, solid, liquid, or gas), and are blended prior to combustion, use the following procedures to determine the appropriate CO_2 emission factor and HHV for the blend.

(i) If the fuels to be blended are received separately, and if the quantity (mass or volume) of each fuel is measured before the fuels are mixed and combusted, then, for each component of the blend, calculate the CO_2 mass emissions separately. Substitute into Equation C–2a of this subpart the total measured mass or volume of the component fuel (from company records), together with the appropriate default CO_2 emission factor from Table C–1, and the annual average HHV, calculated according to § 98.33(a)(2)(ii). In this case, the fact that the fuels are blended prior to combustion is of no consequence.

(ii) If the fuel is received as a blend (*i.e.*, already mixed) or if the components are mixed on site without precisely measuring the mass or volume of each one individually, a reasonable estimate of the relative proportions of the components of the blend must be made, using the best available information (*e.g.*, the approximate annual average mass or volume percentage of each fuel, based on the typical or expected range of values). Determine the appropriate CO_2 emission factor and HHV for use in Equation C–2a of this subpart, as follows:

(A) Consider the blend to be the ''fuel type,'' measure its HHV at the frequency prescribed in paragraph (a)(2)(v) of this section, and determine the annual average HHV value for the blend according to § 98.33(a)(2)(ii).

(B) Calculate a heat-weighted CO_2 emission factor, $(EF)_B$, for the blend, using Equation C–16 of this section. The heat-weighting in Equation C–16 is provided by the default HHVs (from Table C–1) and the estimated mass or volume percentages of the components of the blend.

(C) Substitute into Equation C–2a of this subpart, the annual average HHV for the blend (from paragraph (a)(3)(ii)(A) of this section) and the calculated value of $(EF)_B$, along with the total mass or volume of the blend combusted during the reporting year, to determine the annual CO_2 mass emissions from combustion of the blend.

$$(EF)_B = \frac{\sum_{i=1}^{n} \left[(HHV)_i \, (\%Fuel)_i \, (EF)_i \right]}{(HHV)_B} \quad \text{(Eq. C-16)}$$

where:

$(EF)_B$ = Heat-weighted CO_2 emission factor for the blend (kg CO_2/mmBtu)

$(HHV)_i$ = Default high heat value for fuel "i" in the blend, from Table C–1 (mmBtu per mass or volume)

$(\%Fuel)_i$ = Estimated mass or volume percentage of fuel "i" (mass % or volume %, as applicable, expressed as a decimal fraction; *e.g.*, 25% = 0.25)

$(EF)_i$ = Default CO_2 emission factor for fuel "i" from Table C–1 (mmBtu per mass or volume)

$(HHV)_B$ = Annual average high heat value for the blend, calculated according to § 98.33(a)(2)(ii) (mmBtu per mass or volume)

(iii) Note that for the case described in paragraph (a)(3)(ii) of this section, if measured HHV values for the individual fuels in the blend or for the blend itself are not routinely received at the minimum frequency prescribed in paragraph (a)(2) of this section (or at a greater frequency), and if the unit qualifies to use Tier 1, calculate $(HHV)_B$*, the heat-weighted default HHV for the blend, using Equation C–17 of this section. Then, use Equation C–16 of this section, replacing the term $(HHV)_B$ with $(HHV)_B$* in the denominator, to determine the heat-weighted CO_2 emission factor for the blend. Finally, substitute into Equation C–1 of this subpart, the calculated values of $(HHV)_B$* and $(EF)_B$, along with the total mass or volume of the blend combusted during the reporting year, to determine the annual CO_2 mass emissions from combustion of the blend.

$$HHV_B^{*} = \sum_{i=1}^{n} \left[(HHV)_i \, (\%Fuel)_i \right] \quad \text{(Eq. C-17)}$$

where:

$(HHV)_B$* = Heat-weighted default high heat value for the blend (mmBtu per mass or Volume)

$(HHV)_i$ = Default high heat value for fuel "i" in the blend, from Table C–1 (mmBtu per mass or volume)

$(\%Fuel)_i$ = Estimated mass or volume percentage of fuel "i" in the blend (mass % or volume %, as applicable, expressed as a decimal fraction)

(iv) If the fuel blend described in paragraph (a)(3)(ii) of this section consists of a mixture of fuel(s) listed in Table C–1 of this subpart and one or more fuels not listed in Table C–1, calculate CO_2 and other GHG emissions only for the Table C–1 fuel(s), using the best available estimate of the mass or volume percentage(s) of the Table C–1 fuel(s) in the blend. In this case, Tier 1 shall be used, with the following modifications to Equations C–17 and C–1, to account for the fact that not all of the fuels in the blend are listed in Table C–1:

(A) In Equation C–17, apply the term $(Fuel)_i$ only to the Table C–1 fuels. For each Table C–1 fuel, $(Fuel)_i$ will be the estimated mass or volume percentage of the fuel in the blend, divided by the sum of the mass or volume percentages of the Table C–1 fuels. For example, suppose that a blend consists of two Table C–1 fuels ("A" and "B") and one fuel type ("C") not listed in the Table, and that the volume percentages of fuels A, B, and C in the blend, expressed as decimal fractions, are, respectively, 0.50, 0.30, and 0.20. The term $(Fuel)_i$ in Equation C–17 for fuel A will be 0.50/(0.50 + 0.30) = 0.625, and for fuel B, $(Fuel)_i$ will be 0.30/(0.50 + 0.30) = 0.375.

(B) In Equation C–1, the term "Fuel" will be equal to the total mass or volume of the blended fuel combusted during the year multiplied by the sum of the mass or volume percentages of the Table C–1 fuels in the blend. For the example in paragraph (a)(3)(iv)(A) of this section, ''Fuel'' = (Annual volume of the blend combusted)(0.80).

(4) If, for a particular type of fuel, HHV sampling and analysis is performed more often than the minimum frequency specified in paragraph (a)(2) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(5) If, for a particular type of fuel, valid HHV values are obtained at less than the minimum frequency specifed in paragraph (a)(2) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with missing data procedures of § 98.35.

(6) You must use one of the following appropriate fuel sampling and analysis methods. The HHV may be calculated using chromatographic analysis together with standard heating values of the fuel constituents, provided that the gas chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions. Alternatively, you may use a method published by a consensus-based standards organization if such a method exists, or you may use industry standard practice to determine the high heat values. 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*). The method(s) used shall be documented in the Monitoring Plan required under § 98.3(g)(5).

(b) For the Tier 3 Calculation Methodology:

(1) You must calibrate each oil and gas flow meter according to § 98.3(i) and the provisions of this paragraph (b)(1).

(i) Perform calibrations using any of the test methods and procedures in this paragraph (b)(1)(i). The method(s) used shall be documented in the Monitoring Plan required under § 98.3(g)(5).

(A) You may use the calibration procedures specified by the flow meter manufacturer.

(B) You may use an appropriate flow meter calibration method published by a consensus-based standards organization, if such a method exists. 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*).

(C) You may use an industry-accepted practice.

(ii) In addition to the initial calibration required by § 98.3(i), recalibrate each fuel flow meter (except as otherwise provided in paragraph (b)(1)(iii) of this section) according to one of the following. You may recalibrate annually, at the minimum frequency specified by the manufacturer, or at the interval specified by industry standard practice.

(iii) Fuel billing meters are exempted from the initial and ongoing calibration requirements of this paragraph and from the Monitoring Plan and recordkeeping requirements of §§ 98.3(g)(5)(i)(C), (g)(6), and (g)(7), provided that the fuel supplier and the unit combusting the fuel do not have any common owners and are not owned by subsidiaries or affiliates of the same company. Meters used exclusively to measure the flow rates of fuels that are only used for unit startup are also exempted from the initial and ongoing calibration requirements of this paragraph.

(iv) For the initial calibration of an orifice, nozzle, or venturi meter; in-situ calibration of the transmitters is sufficient. A primary element inspection (PEI) shall be performed at least once every three years.

(v) For the continuously-operating units and processes described in § 98.3(i)(6), the required flow meter recalibrations and, if necessary, the PEIs may be postponed until the next scheduled maintenance outage.

(vi) If a mixture of liquid or gaseous fuels is transported by a common pipe, you may either separately meter each of the fuels prior to mixing, using flow meters calibrated according to § 98.3(i), or consider the fuel mixture to be the ''fuel type'' and meter the mixed fuel, using a flow meter calibrated according to § 98.3(i).

(2) Oil tank drop measurements (if used to determine liquid fuel use volume) shall be performed according to any an appropriate method published by a consensus-based standards organization (e.g., the American Petroleum Institute).

(3) The carbon content and, if applicable, molecular weight of the fuels shall be determined according to the procedures in this paragraph (b)(3).

(i) All fuel samples shall be taken at a location in the fuel handling system that provides a sample representative of the fuel combusted. The fuel sampling and analysis may be performed by either the owner or operator or by the supplier of the fuel.

(ii) For each type of fuel, the minimum required frequency for collecting and analyzing samples for carbon content and (if applicable) molecular weight is specified in this paragraph. When the sampling frequency is based on a specified time period (*e.g.*, week, month, quarter, or half-year), fuel sampling and analysis is required for only those time periods in which the fuel is combusted.

(A) For natural gas, semiannual sampling and analysis is required (*i.e.*, twice in a calendar year, with consecutive samples taken at least four months apart).

(B) For coal and fuel oil and for any other solid or liquid fuel that is delivered in lots, analysis of at least one representative sample from each fuel lot is required. For fuel oil, as an alternative to sampling each fuel lot, a sample may be taken upon each addition of oil to the storage tank. Flow proportional sampling, continuous drip sampling, or daily manual oil sampling may also be used, in lieu of sampling each fuel lot. If the daily manual oil sampling option is selected, sampling from a particular tank is required only on days when oil from the tank is combusted by the unit (or units) served by the tank. If you elect to sample from the storage tank upon each addition of oil to the tank, you must take at least one sample from each tank that is currently in service and whenever oil is added to the tank, for as long as the tank remains in service. You need not take any samples from a storage tank while it is out of service. Rather, take a sample when the tank is brought into service and whenever oil is added to the tank, for as long as the tank remains in service. If multiple additions of oil are made to a particular in service tank on a given day (*e.g.*, from multiple deliveries), one sample taken after the final addition of oil is sufficient. For the purposes of this section, a fuel lot is defined as a shipment or delivery of a single type of fuel (*e.g.*, ship load, barge load, group of trucks, group of railroad cars, oil delivery via pipeline from a tank farm, *etc.*). However, if multiple deliveries of a particular type of fuel are received from the same supply source in a given calendar month, the deliveries for that month may be considered, collectively, to comprise a fuel lot, requiring only one representative sample, subject to the following conditions:

(*1*) For coal, the ''type'' of fuel means the rank of the coal (*i.e.*, anthracite, bituminous, sub-bituminous, or lignite). For fuel oil, the ''type'' of fuel means the grade number or classification of the oil (*e.g.*, No. 1 oil, No. 2 oil, kerosene, Jet A fuel, *etc.*).

(*2*) The owner or operator shall document in the monitoring plan under § 98.3(g)(5) how the monthly sampling of each type of fuel is performed.

(C) For liquid fuels other than fuel oil and for biogas, sampling and analysis is required at least once per calendar quarter. To the extent practicable, consecutive quarterly samples shall be taken at least 30 days apart.

(D) For other solid fuels (except MSW), weekly sampling is required to obtain composite samples, which are then analyzed monthly.

(E) For gaseous fuels other than natural gas and biogas (*e.g.*, process gas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if continuous, on-line equipment, such as a gas chromatograph, is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed.

(F) For mixtures (blends) of solid fuels, weekly sampling is required to obtain composite samples, which are analyzed monthly. For blends of liquid fuels, and for gas mixtures consisting only of natural gas and biogas, sampling and analysis is required at least once per calendar quarter. For gas mixtures that contain gases other than natural gas (including biogas), daily sampling and analysis to determine the carbon content and molecular weight of the fuel is required if continuous, on-line equipment is in place to make these measurements. Otherwise, weekly sampling and analysis shall be performed.

(iii) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed more often than the minimum frequency specified in paragraph (b)(3) of this section, the results of all valid fuel analyses shall be used in the GHG emission calculations.

(iv) If, for a particular type of fuel, sampling and analysis for carbon content and molecular weight is performed at less than the minimum frequency specified in paragraph (b)(3) of this section, appropriate substitute data values shall be used in the emissions calculations, in accordance with the missing data procedures of § 98.35.

(v) To calculate the CO_2 mass emissions from combustion of a blend of fuels in the same state of matter (solid, liquid, or gas), you may either:

(A) Apply Equation C–3, C–4 or C–5 of this subpart (as applicable) to each component of the blend, if the mass or volume, the carbon content, and (if applicable), the molecular weight of each component are accurately measured prior to blending; or

(B) Consider the blend to be the ''fuel type.'' Then, at the frequency specified in paragraph (b)(3)(ii)(F) of this section, measure the carbon content and, if applicable, the molecular weight of the blend and calculate the annual average value of each parameter in the manner described in § 98.33(a)(2)(ii). Also measure the mass or volume of the blended fuel combusted during the reporting year. Substitute these measured values into Equation C–3, C–4, or C–5 of this subpart (as applicable).

(4) You must use one of the following appropriate fuel sampling and analysis methods. 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. Alternatively, you may use a method published by a consensus-based standards organization if such a method exists, or you may use industry standard practice to determine the carbon content and molecular weight (for gaseous fuel) of the fuel. 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*). The method(s) used shall be documented in the Monitoring Plan required under § 98.3(g)(5).

(c) For the Tier 4 Calculation Methodology, the CO_2, flow rate, and (if applicable) moisture monitors must be certified prior to the applicable deadline specified in § 98.33(b)(5).

(1) For initial certification, you may use any one of the following three procedures in this paragraph.

(i) §§ 75.20(c)(2), (c)(4), and (c)(5) through (c)(7) of this chapter and appendix A to part 75 of this chapter.

(ii) The calibration drift test and relative accuracy test audit (RATA) procedures of Performance Specification 3 in appendix B to part 60 of this chapter (for the CO_2 concentration monitor) and Performance Specification 6 in appendix B to part 60 of this chapter (for the continuous emission rate monitoring system (CERMS)).

(iii) The provisions of an applicable State continuous monitoring program.

(2) If an O_2 concentration monitor is used to determine CO_2 concentrations, the applicable provisions of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program shall be followed for initial certification and on-going quality assurance, and all required RATAs of the monitor shall be done on a percent CO_2 basis.

(3) For ongoing quality assurance, follow the applicable procedures in either appendix B to part 75 of this chapter, appendix F to part 60 of this chapter, or an applicable State continuous monitoring program. If appendix F to part 60 of this chapter is selected for on-going quality assurance, perform daily calibration drift assessments for both the CO_2 monitor (or surrogate O_2 monitor) and the flow rate monitor, conduct cylinder gas audits of the CO_2 concentration monitor in three of the four quarters of each year (except for non-operating quarters), and perform annual RATAs of the CO_2 concentration monitor and the CERMS.

(4) For the purposes of this part, the stack gas volumetric flow rate monitor RATAs required by appendix B to part 75 of this chapter and the annual RATAs of the CERMS required by appendix F to part 60 of this chapter need only be done at one operating level, representing normal load or normal process operating conditions, both for initial certification and for ongoing quality assurance.

(5) If, for any source operating hour, quality assured data are not obtained with a CO_2 monitor (or surrogate O_2 monitor), flow rate monitor, or (if applicable) moisture monitor, use appropriate substitute data values in accordance with the missing data provisions of § 98.35.

(6) For certain applications where combined process emissions and combustion emissions are measured, the CO_2 concentrations in the flue gas may be considerably higher than for combustion emissions alone. In such cases, the span of the CO_2 monitor may, if necessary, be set higher than the specified levels in the applicable regulations. If the CO_2 span value is set higher than 20 percent CO_2, the cylinder gas audits of the CO_2 monitor under appendix F to part 60 of this chapter may be performed at 40 to 60 percent and 80 to 100 percent of span, in lieu of the prescribed calibration levels of 5 to 8 percent CO_2 and 10 to 14 percent CO_2.

(7) Hourly average data from the CEMS shall be validated in a manner consistent with one of the following: §§ 60.13(h)(2)(i) through (h)(2)(vi) of this chapter; § 75.10(d)(1) of this chapter; or the hourly data validation requirements of an applicable State CEM regulation.

(d) Except as otherwise provided in § 98.33 (b)(1)(vi) and (b)(1)(vii), when municipal solid waste (MSW) is either the primary fuel combusted in a unit or the only fuel with a biogenic component combusted in the unit, determine the biogenic portion of the CO_2 emissions using ASTM D6866–08 Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis (incorporated by reference, see § 98.7) and ASTM D7459–08 Standard Practice for Collection of Integrated Samples for the Speciation of Biomass

(Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources (incorporated by reference, see § 98.7). Perform the ASTM D7459–08 sampling and the ASTM D6866–08 analysis at least once in every calendar quarter in which MSW is combusted in the unit. Collect each gas sample during normal unit operating conditions for at least 24 total (not necessarily consecutive) hours, or longer if the facility deems it necessary to obtain a representative sample. Notwithstanding this requirement, if the types of fuels combusted and their relative proportions are consistent throughout the year, the minimum required sampling time may be reduced to 8 hours if at least two 8-hour samples and one 24-hour sample are collected under normal operating conditions, and arithmetic average of the biogenic fraction of the flue gas from the 8-hour samples (expressed as a decimal) is within ±5 percent of the biogenic fraction from the 24-hour test. There must be no overlapping of the 8-hour and 24-hour test periods. Document the results of the demonstration in the unit's monitoring plan. If the types of fuels and their relative proportions are not consistent throughout the year, an optional sampling approach that facilities may wish to consider to obtain a more representative sample is to collect an integrated sample by extracting a small amount of flue gas (*e.g.*, 1 to 5 cc) in each unit operating hour during the quarter. Separate the total annual CO_2 emissions into the biogenic and non-biogenic fractions using the average proportion of biogenic emissions of all samples analyzed during the reporting year. Express the results as a decimal fraction (*e.g.*, 0.30, if 30 percent of the CO_2 is biogenic). When MSW is the primary fuel for multiple units at the facility, and the units are fed from a common fuel source, testing at only one of the units is sufficient.

(e) For other units that combust combinations of biomass fuel(s) (or heterogeneous fuels that have a biomass component, *e.g.*, tires) and fossil (or other non-biogenic) fuel(s), in any proportions, ASTM D6866–08 (incorporated by reference, see § 98.7) and ASTM D7459–08 (incorporated by reference, see § 98.7) may be used to determine the biogenic portion of the CO_2 emissions in every calendar quarter in which biomass and non-biogenic fuels are co-fired in the unit. Follow the procedures in paragraph (d) of this section. If the primary fuel for multiple units at the facility consists of tires, and the units are fed from a common fuel source, testing at only one of the units is sufficient.

(f) The records required under § 98.3(g)(2)(i) shall include an explanation of how the following parameters are determined from company records (or, if applicable, from the best available information):

(1) Fuel consumption, when the Tier 1 and Tier 2 Calculation Methodologies are used, including cases where § 98.36(c)(4) applies.

(2) Fuel consumption, when solid fuel is combusted and the Tier 3 Calculation Methodology is used.

(3) Fossil fuel consumption when § 98.33(e)(2) applies to a unit that uses CEMS to quantify CO_2 emissions and that combusts both fossil and biomass fuels.

(4) Sorbent usage, when § 98.33(d) applies.

(5) Quantity of steam generated by a unit when § 98.33(a)(2)(iii) applies.

(6) Biogenic fuel consumption and high heating value, as applicable, under §§ 98.33(e)(5) and (e)(6).

(7) Fuel usage for CH_4 and N_2O emissions calculations under § 98.33(c)(4)(ii).

(8) Mass of biomass combusted, for premixed fuels that contain biomass and fossil fuels under § 98.33(e)(1)(iii).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79146, Dec. 17, 2010]

§ 98.35 Procedures for estimating missing data.

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 all units subject to the requirements of the Acid Rain Program, and all other stationary combustion units subject to the requirements of this part that monitor and report emissions and heat input data year-round in accordance with part 75 of this chapter, the missing data substitution procedures in part 75 of this chapter shall be followed for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

(b) For units that use the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies, perform missing data substitution as follows for each parameter:

(1) For each missing value of the high heating value, 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 has not been obtained by the time that the GHG emissions report is due, you may use the ''before'' value for missing data substitution or the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours). 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.

(2) For missing records of CO_2 concentration, stack gas flow rate, percent moisture, fuel usage, and sorbent usage, the substitute data value shall be the best available estimate of the parameter, based on all available process data (e.g., electrical load, steam production, operating hours, etc.). You must document and retain records of the procedures used for all such estimates.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79150, Dec. 17, 2010]

§98.36 Data reporting requirements.

(a) In addition to the facility-level information required under §98.3, the annual GHG emissions report shall contain the unit-level or process-level emissions data in paragraphs (b) through (d) of this section (as applicable) and the emissions verification data in paragraph (e) of this section.

(b) *Units that use the four tiers.* You shall report the following information for stationary combustion units that use the Tier 1, Tier 2, Tier 3, or Tier 4 methodology in §98.33(a) to calculate CO_2 emissions, except as otherwise provided in paragraphs (c) and (d) of this section:

(1) The unit ID number.

(2) A code representing the type of unit.

(3) Maximum rated heat input capacity of the unit, in mmBtu/hr.

(4) Each type of fuel combusted in the unit during the report year.

(5) The methodology (*i.e.*, tier) used to calculate the CO_2 emissions for each type of fuel combusted (*i.e.*, Tier 1, 2, 3, or 4).

(6) The methodology start date, for each fuel type.

(7) The methodology end date, for each fuel type.

(8) For a unit that uses Tiers 1, 2, or 3:

(i) The annual CO_2 mass emissions (including biogenic CO_2), and the annual CH_4, and N_2O mass emissions for each type of fuel combusted during the reporting year, expressed in metric tons of each gas and in metric tons of CO_2e; and

(ii) Metric tons of biogenic CO_2 emissions (if applicable).

(9) For a unit that uses Tier 4:

(i) If the total annual CO_2 mass emissions measured by the CEMS consists entirely of non-biogenic CO_2 (*i.e.*, CO_2 from fossil fuel combustion plus, if applicable, CO_2 from sorbent and/or process CO_2), report the total annual CO_2 mass emissions, expressed in metric tons. You are not required to report the combustion CO_2 emissions by fuel type.

(ii) Report the total annual CO_2 mass emissions measured by the CEMS. If this total includes both biogenic and non-biogenic CO_2, separately report the annual non-biogenic CO_2 mass emissions and the annual CO_2 mass emissions from biomass combustion, each expressed in metric tons. You are not required to report the combustion CO_2 emissions by fuel type.

(iii) An estimate of the heat input from each type of fuel listed in Table C–2 of this subpart that was combusted in the unit during the report year, and the annual CH_4 and N_2O emissions for each of these fuels, expressed in metric tons of each gas and in metric tons of CO_2e.

(10) Annual CO_2 emissions from sorbent (if calculated using Equation C–11 of this subpart), expressed in metric tons.

(11) If applicable, the plant code (as defined in § 98.6).

(c) *Reporting alternatives for units using the four Tiers.* You may use any of the applicable reporting alternatives of this paragraph to simplify the unit-level reporting required under paragraph (b) of this section:

(1) *Aggregation of units.* If a facility contains two or more units (e.g., boilers or combustion turbines), each of which has a maximum rated heat input capacity of 250 mmBtu/hr or less, you may report the combined GHG emissions for the group of units in lieu of reporting GHG emissions from the individual units, provided that the use of Tier 4 is not required or elected for any of the units and the units use the same tier for any common fuels combusted. If this option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Group ID number, beginning with the prefix ''GP''.

(ii)–(iii) [Reserved]

(iv) The highest maximum rated heat input capacity of any unit in the group (mmBtu/hr).

(v) Each type of fuel combusted in the group of units during the reporting year.

(vi) Annual CO_2 mass emissions and annual CH_4, and N_2O mass emissions, aggregated for each type of fuel combusted in the group of units during the report year, expressed in metric tons of each gas and in metric tons of CO_2e. If any of the units burn both fossil fuels and biomass, report also the annual CO_2 emissions from combustion of all fossil fuels combined and annual CO_2 emissions from combustion of all biomass fuels combined, expressed in metric tons.

(vii) The methodology (*i.e.*, tier) used to calculate the CO_2 mass emissions for each type of fuel combusted in the units (*i.e.*, Tier 1, Tier 2, or Tier 3).

(viii) The methodology start date, for each fuel type.

(ix) The methodology end date, for each fuel type.

(x) The calculated CO_2 mass emissions (if any) from sorbent expressed in metric tons.

(xi) If applicable, the plant code (as defined in § 98.6).

(2) *Monitored common stack or duct configurations.* When the flue gases from two or more stationary fuel combustion units at a facility are combined together in a common stack or duct before exiting to the atmosphere and if CEMS are used to continuously monitor CO_2 mass emissions at the common stack or duct according to the Tier 4 Calculation Methodology, you may report the combined emissions from the units sharing the common stack or duct, in lieu of separately reporting the GHG emissions from the individual units. This monitoring and reporting alternative may also be used when process off-gases or a mixture of combustion products and process gases are combined together in a common stack or duct before exiting to the atmosphere. Whenever the common stack or duct monitoring option is applied, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common stack or duct identification number, beginning with the prefix ''CS''.

(ii) Number of units sharing the common stack or duct. Report ''1'' when the flue gas flowing through the common stack or duct includes combustion products and/or process off-gases, and all of the effluent comes from a single unit (*e.g.*, a furnace, kiln, petrochemical production unit, or smelter).

(iii) Combined maximum rated heat input capacity of the units sharing the common stack or duct (mmBtu/hr). This data element is required only when all of the units sharing the common stack are stationary fuel combustion units.

(iv) Each type of fuel combusted in the units during the year.

(v) The methodology (tier) used to calculate the CO_2 mass emissions, *i.e.*, Tier 4.

(vi) The methodology start date.

(vii) The methodology end date.

(viii) Total annual CO_2 mass emissions measured by the CEMS, expressed in metric tons. If any of the units burn both fossil fuels and biomass, separately report the annual non-biogenic CO_2 mass emissions (*i.e.*, CO_2 from fossil fuel combustion plus, if applicable, CO_2 from sorbent and/or process CO_2) and the annual CO_2 mass emissions from biomass combustion, each expressed in metric tons.

(ix) An estimate of the heat input from each type of fuel listed in Table C–2 of this subpart that was combusted during the report year in the units sharing the common stack or duct during the report year, and, for each of these fuels, the annual CH_4 and N_2O mass emissions from the units sharing the common stack or duct, expressed in metric tons of each gas and in metric tons of CO_2e.

(x) Reserved.

(xi) If applicable, the plant code (as defined in § 98.6).

(3) *Common pipe configurations.* When two or more stationary combustion units at a facility combust the same type of liquid or gaseous fuel and the fuel is fed to the individual units through a common supply line or pipe, you may report the combined emissions from the units served by the common supply line, in lieu of separately reporting the GHG emissions from the individual units, provided that the total amount of fuel combusted by the units is accurately measured at the common pipe or supply line using a fuel flow meter, or, for natural gas, the amount of fuel combusted may be obtained from gas billing records. For Tier 3 applications, the flow meter shall be calibrated in accordance with § 98.34(b). If a portion of the fuel measured (or obtained from gas billing records) at the main supply line is diverted to either: A flare; or another stationary fuel combustion unit (or units), including units that use a CO_2 mass emissions calculation method in part 75 of this chapter; or a chemical or industrial process (where it is used as a raw material but not combusted), and the remainder of the fuel is distributed to a group of combustion units for which you elect to use the common pipe reporting option, you may use company records to subtract out the diverted portion of the fuel from the fuel measured (or obtained from gas billing records) at the main supply line prior to performing the GHG emissions calculations for the group of units using the common pipe option. If the diverted portion of the fuel is combusted, the GHG emissions from the diverted portion shall be accounted for in accordance with the applicable provisions of this part. When the common pipe option is selected, the applicable tier shall be used based on the maximum rated heat input capacity of the largest unit served by the common pipe configuration, except where the applicable tier is based on criteria other than unit size. For example, if the maximum rated heat input capacity of the largest unit is greater than 250 mmBtu/hr, Tier 3 will apply, unless the fuel transported through the common pipe is natural gas or distillate oil, in which case Tier 2 may be used, in accordance with § 98.33(b)(2)(ii). As a second example, in accordance with § 98.33(b)(1)(v), Tier 1 may be used regardless of unit size when natural gas is transported through the common pipe, if the annual fuel consumption is obtained from gas billing records in units of therms or mmBtu. When the common pipe reporting option is selected, the following information shall be reported instead of the information in paragraph (b) of this section:

(i) Common pipe identification number, beginning with the prefix ''CP''.

(ii) [Reserved]

(iii) The highest maximum rated heat input capacity of any unit served by the common pipe (mmBtu/hr).

(iv) The fuels combusted in the units during the reporting year.

(v) The methodology used to calculate the CO_2 mass emissions (i.e., Tier 1, Tier 2, or Tier 3).

(vi) If the any of the units burns both fossil fuels and biomass, the annual CO_2 mass emissions from combustion of all fossil fuels and annual CO_2 emissions from combustion of all biomass fuels from the units served by the common pipe, expressed in metric tons.

(vii) Annual CO_2 mass emissions and annual CH_4 and N_2O emissions from each fuel type for the units served by the common pipe, expressed in metric tons of each gas and in metric tons of CO_2e.

(viii) Methodology start date.

(ix) Methodology end date.

(x) If applicable, the plant code (as defined in § 98.6).

(4) The following alternative reporting option applies to facilities at which a common liquid or gaseous fuel supply is shared between one or more large combustion units, such as boilers or combustion turbines (including units subject to subpart D of this part and other units subject to part 75 of this chapter) and small combustion sources, including, but not limited to, space heaters, hot water heaters, and lab burners. In this case, you may simplify reporting by attributing all of the GHG emissions from combustion of the shared fuel to the large combustion unit(s), provided that:

(i) The total quantity of the fuel combusted during the report year in the units sharing the fuel supply is measured, either at the ''gate'' to the facility or at a point inside the facility, using a fuel flow meter, billing meter, or tank drop measurements (as applicable);

(ii) On an annual basis, at least 95 percent (by mass or volume) of the shared fuel is combusted in the large combustion unit(s), and the remainder is combusted in the small combustion sources. Company records may be used to determine the percentage distribution of the shared fuel to the large and small units; and

(iii) The use of this reporting option is documented in the Monitoring Plan required under § 98.3(g)(5). Indicate in the Monitoring Plan which units share the common fuel supply and the method used to demonstrate that this alternative reporting option applies. For the small combustion sources, a description of the types of units and the approximate number of units is sufficient.

(d) *Units subject to part 75 of this chapter.* (1) For stationary combustion units that are subject to subpart D of this part, you shall report the following unit-level information:

(i) Unit or stack identification numbers. Use exact same unit, common stack, common pipe, or multiple stack identification numbers that represent the monitored locations (*e.g.*, 1, 2, CS001, MS1A, CP001, *etc.*) that are reported under § 75.64 of this chapter.

(ii) Annual CO_2 emissions at each monitored location, expressed in both short tons and metric tons. Separate reporting of biogenic CO_2 emissions under § 98.3(c)(4)(ii) and § 98.3(c)(4)(iii)(A) is optional only for the 2010 reporting year, as provided in § 98.3(c)(12).

(iii) Annual CH_4 and N_2O emissions at each monitored location, for each fuel type listed in Table C–2 that was combusted during the year (except as otherwise provided in § 98.33(c)(4)(ii)(B)), expressed in metric tons of CO_2e.

(iv) The total heat input from each fuel listed in Table C–2 that was combusted during the year (except as otherwise provided in § 98.33(c)(4)(ii)(B)), expressed in mmBtu.

(v) Identification of the Part 75 methodology used to determine the CO_2 mass emissions.

(vi) Methodology start date.

(vii) Methodology end date.

(viii) Acid Rain Program indicator.

(ix) Annual CO_2 mass emissions from the combustion of biomass, expressed in metric tons of CO_2e, except where the reporting provisions of §§ 98.3(c)(12)(i) through (c)(12)(iii) are implemented for the 2010 reporting year.

(x) If applicable, the plant code (as defined in § 98.6).

(2) For units that use the alternative CO_2 mass emissions calculation methods provided in § 98.33(a)(5), you shall report the following unit-level information:

(i) Unit, stack, or pipe ID numbers. Use exact same unit, common stack, common pipe, or multiple stack identification numbers that represent the monitored locations (*e.g.*, 1, 2, CS001, MS1A, CP001, *etc.*) that are reported under § 75.64 of this chapter.

(ii) For units that use the alternative methods specified in § 98.33(a)(5)(i) and (ii) to monitor and report heat input data year-round according to appendix D to part 75 of this chapter or § 75.19 of this chapter:

(A) Each type of fuel combusted in the unit during the reporting year.

(B) The methodology used to calculate the CO_2 mass emissions for each fuel type.

(C) Methodology start date.

(D) Methodology end date.

(E) A code or flag to indicate whether heat input is calculated according to appendix D to part 75 of this chapter or § 75.19 of this chapter.

(F) Annual CO_2 emissions at each monitored location, across all fuel types, expressed in metric tons of CO_2e.

(G) Annual heat input from each type of fuel listed in Table C–2 of this subpart that was combusted during the reporting year, expressed in mmBtu.

(H) Annual CH_4 and N_2O emissions at each monitored location, from each fuel type listed in Table C–2 of this subpart that was combusted during the reporting year (except as otherwise provided in § 98.33(c)(4)(ii)(D)), expressed in metric tons CO_2e.

(I) Annual CO_2 mass emissions from the combustion of biomass, expressed in metric tons CO_2e, except where the reporting provisions of §§ 98.3(c)(12)(i) through (c)(12)(iii) are implemented for the 2010 reporting year.

(J) If applicable, the plant code (as defined in § 98.6).

(iii) For units with continuous monitoring systems that use the alternative method for units with continuous monitoring systems in § 98.33(a)(5)(iii) to monitor heat input year-round according to part 75 of this chapter:

(A) Each type of fuel combusted during the reporting year.

(B) Methodology used to calculate the CO_2 mass emissions.

(C) Methodology start date.

(D) Methodology end date.

(E) A code or flag to indicate that the heat input data is derived from CEMS measurements.

(F) The total annual CO_2 emissions at each monitored location, expressed in metric tons of CO_2e.

(G) Annual heat input from each type of fuel listed in Table C–2 of this subpart that was combusted during the reporting year, expressed in mmBtu.

(H) Annual CH_4 and N_2O emissions at each monitored location, from each fuel type listed in Table C–2 of this subpart that was combusted during the reporting year (except as otherwise provided in § 98.33(c)(4)(ii)(B)), expressed in metric tons CO_2e.

(I) Annual CO_2 mass emissions from the combustion of biomass, expressed in metric tons CO_2e, except where the reporting provisions of §§ 98.3(c)(12)(i) through (c)(12)(iii) are implemented for the 2010 reporting year.

(J) If applicable, the plant code (as defined in § 98.6).

(e) *Verification data.* You must keep on file, in a format suitable for inspection and auditing, sufficient data to verify the reported GHG emissions. This data and information must, where indicated in this paragraph (e), be included in the annual GHG emissions report.

(1) The applicable verification data specified in this paragraph (e) are not required to be kept on file or reported for units that meet any one of the three following conditions:

(i) Are subject to the Acid Rain Program.

(ii) Use the alternative methods for units with continuous monitoring systems provided in § 98.33(a)(5).

(iii) Are not in the Acid Rain Program, but are required to monitor and report CO_2 mass emissions and heat input data year-round, in accordance with part 75 of this chapter.

(2) For stationary combustion sources using the Tier 1, Tier 2, Tier 3, and Tier 4 Calculation Methodologies in § 98.33(a) to quantify CO_2 emissions, the following additional information shall be kept on file and included in the GHG emissions report, where indicated:

(i) For the Tier 1 Calculation Methodology, report the total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during the reporting year, in short tons for solid fuels, gallons for liquid fuels and standard cubic feet for gaseous fuels, or, if applicable, therms or mmBtu for natural gas.

(ii) For the Tier 2 Calculation Methodology, report:

(A) The total quantity of each type of fuel combusted in the unit or group of aggregated units (as applicable) during each month of the reporting year. Express the quantity of each fuel combusted during the measurement period in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of the HHV determinations (e.g., once a month, once per fuel lot).

(C) The high heat values used in the CO_2 emissions calculations for each type of fuel combusted during the reporting year, in mmBtu per short ton for solid fuels, mmBtu per gallon for liquid fuels, and mmBtu per scf for gaseous fuels. Report a HHV value for each calendar month in which HHV determination is required. If multiple values are obtained in a given month, report the arithmetic average value for the month. Indicate whether each reported HHV is a measured value or a substitute data value.

(D) If Equation C–2c of this subpart is used to calculate CO_2 mass emissions, report the total quantity (*i.e.,* pounds) of steam produced from MSW or solid fuel combustion during each month of the reporting year, and the ratio of the maximum rate heat input capacity to the design rated steam output capacity of the unit, in mmBtu per lb of steam.

(iii) For the Tier 2 Calculation Methodology, keep records of the methods used to determine the HHV for each type of fuel combusted and the date on which each fuel sample was taken, except where fuel sampling data are received from the fuel supplier. In that case, keep records of the dates on which the results of the fuel analyses for HHV are received.

(iv) For the Tier 3 Calculation Methodology, report:

(A) The quantity of each type of fuel combusted in the unit or group of units (as applicable) during each month of the reporting year, in short tons for solid fuels, gallons for liquid fuels, and scf for gaseous fuels.

(B) The frequency of carbon content and, if applicable, molecular weight determinations for each type of fuel for the reporting year (e.g., daily, weekly, monthly, semiannually, once per fuel lot).

(C) The carbon content and, if applicable, gas molecular weight values used in the emission calculations (including both valid and substitute data values). For each calendar month of the reporting year in which carbon content and, if applicable, molecular weight determination is required, report a value of each parameter. If multiple values of a parameter are obtained in a given month, report the arithmetic average value for the month. Express carbon content as a decimal fraction for solid fuels, kg C per gallon for liquid fuels, and kg C per kg of fuel for gaseous fuels. Express the gas molecular weights in units of kg per kg-mole.

(D) The total number of valid carbon content determinations and, if applicable, molecular weight determinations made during the reporting year, for each fuel type.

(E) The number of substitute data values used for carbon content and, if applicable, molecular weight used in the annual GHG emissions calculations.

(F) The annual average HHV, when measured HHV data, rather than a default HHV from Table C–1 of this subpart, are used to calculate CH_4 and N_2O emissions for a Tier 3 unit, in accordance with § 98.33(c)(1).

(G) The value of the molar volume constant (MVC) used in Equation C–5 (if applicable).

(v) For the Tier 3 Calculation Methodology, keep records of the following:

(A) For liquid and gaseous fuel combustion, the dates and results of the initial calibrations and periodic recalibrations of the required fuel flow meters.

(B) For fuel oil combustion, the method from § 98.34(b) used to make tank drop measurements (if applicable).

(C) The methods used to determine the carbon content and (if applicable) the molecular weight of each type of fuel combusted.

(D) The methods used to calibrate the fuel flow meters).

(E) The date on which each fuel sample was taken, except where fuel sampling data are received from the fuel supplier. In that case, keep records of the dates on which the results of the fuel analyses for carbon content and (if applicable) molecular weight are received.

(vi) For the Tier 4 Calculation Methodology, report:

(A) The total number of source operating hours in the reporting year.

(B) The cumulative CO_2 mass emissions in each quarter of the reporting year, i.e., the sum of the hourly values calculated from Equation C–6 or C–7 of this subpart (as applicable), in metric tons.

(C) For CO_2 concentration, stack gas flow rate, and (if applicable) stack gas moisture content, the percentage of source operating hours in which a substitute data value of each parameter was used in the emissions calculations.

(vii) For the Tier 4 Calculation Methodology, keep records of:

(A) Whether the CEMS certification and quality assurance procedures of part 75 of this chapter, part 60 of this chapter, or an applicable State continuous monitoring program were used.

(B) The dates and results of the initial certification tests of the CEMS.

(C) The dates and results of the major quality assurance tests performed on the CEMS during the reporting year, i.e., linearity checks, cylinder gas audits, and relative accuracy test audits (RATAs).

(viii) If CO_2 emissions that are generated from acid gas scrubbing with sorbent injection are not captured using CEMS, report:

(A) The total amount of sorbent used during the report year, in short tons.

(B) The molecular weight of the sorbent.

(C) The ratio (''R'') in Equation C–11 of this subpart.

(ix) For units that combust both fossil fuel and biomass, when biogenic CO_2 is determined according to §98.33(e)(2), you shall report the following additional information, as applicable:

(A) The annual volume of CO_2 emitted from the combustion of all fuels,*i.e.*, V_{total}, in scf.

(B) The annual volume of CO_2 emitted from the combustion of fossil fuels, *i.e.*, V_{ff}, in scf. If more than one type of fossil fuel was combusted, report the combustion volume of CO_2 for each fuel separately as well as the total.

(C) The annual volume of CO_2 emitted from the combustion of biomass,*i.e.*, V_{bio}, in scf.

(D) The carbon-based F-factor used in Equation C–13 of this subpart, for each type of fossil fuel combusted, in scf CO_2 per mmBtu.

(E) The annual average HHV value used in Equation C–13 of this subpart, for each type of fossil fuel combusted, in Btu/lb, Btu/gal, or Btu/scf, as appropriate.

(F) The total quantity of each type of fossil fuel combusted during the reporting year, in lb, gallons, or scf, as appropriate.

(G) Annual biogenic CO_2 mass emissions, in metric tons.

(x) When ASTM methods D7459–08 (incorporated by reference, see §98.7) and D6866–08 (incorporated by reference, see §98.7) are used to determine the biogenic portion of the annual CO_2 emissions from MSW combustion, as described in §98.34(d), report:

(A) The results of each quarterly sample analysis, expressed as a decimal fraction (e.g., if the biogenic fraction of the CO_2 emissions from MSW combustion is 30 percent, report 0.30).

(B) The annual biogenic CO_2 mass emissions from MSW combustion, in metric tons.

(xi) When ASTM methods D7459–08 (incorporated by reference, see §98.7) and D6866–08 (incorporated by reference, see §98.7) are used in accordance with §98.34(e) to determine the biogenic portion of the annual CO_2 emissions from a unit that co-fires biogenic fuels (or partly-biogenic fuels, including tires if you are electing to report biogenic CO_2 emissions from tire combustion) and non-biogenic fuels, you shall report the results of each quarterly sample analysis, expressed as a decimal fraction (*e.g.*, if the biogenic fraction of the CO_2 emissions is 30 percent, report 0.30).

(3) Within 30 days of receipt of a written request from the Administrator, you shall submit explanations of the following:

(i) An explanation of how company records are used to quantify fuel consumption, if the Tier 1 or Tier 2 Calculation Methodology is used to calculate CO_2 emissions.

(ii) An explanation of how company records are used to quantify fuel consumption, if solid fuel is combusted and the Tier 3 Calculation Methodology is used to calculate CO_2 emissions.

(iii) An explanation of how sorbent usage is quantified.

(iv) An explanation of how company records are used to quantify fossil fuel consumption in units that uses CEMS to quantify CO_2 emissions and combusts both fossil fuel and biomass.

(v) An explanation of how company records are used to measure steam production, when it is used to calculate CO_2 mass emissions under § 98.33(a)(2)(iii) or to quantify solid fuel usage under § 98.33(c)(3).

(4) Within 30 days of receipt of a written request from the Administrator, you shall submit the verification data and information described in paragraphs (e)(2)(iii), (e)(2)(v), and (e)(2)(vii) of this section.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79151, Dec. 17, 2010; 78 FR 71950, Nov. 29, 2013]

§ 98.37 Records that must be retained.

In addition to the requirements of § 98.3(g), you must retain the applicable records specified in §§ 98.34(f) and (g), 98.35(b), and 98.36(e).

§ 98.38 Definitions.

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

TABLE C–1 TO SUBPART C OF PART 98—DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL

Fuel type	Default high heat value	Default CO_2 emission factor
Coal and coke	mmBtu/short ton	kg CO_2/mmBtu
Anthracite	25.09	103.69
Bituminous	24.93	93.28
Subbituminous	17.25	97.17
Lignite	14.21	97.72
Coal Coke	24.80	113.67
Mixed (Commercial sector)	21.39	94.27
Mixed (Industrial coking)	26.28	93.90
Mixed (Industrial sector)	22.35	94.67
Mixed (Electric Power sector)	19.73	95.52
Natural gas	mmBtu/scf	kg CO_2/mmBtu
(Weighted U.S. Average)	1.026×10^{-3}	53.06
Petroleum products	mmBtu/gallon	kg CO_2/mmBtu
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Used Oil	0.138	74.00
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG) [1]	0.092	61.71
Propane [1]	0.091	62.87
Propylene [2]	0.091	67.77
Ethane [1]	0.068	59.60
Ethanol	0.084	68.44
Ethylene [2]	0.058	65.96
Isobutane [1]	0.099	64.94
Isobutylene [1]	0.103	68.86
Butane [1]	0.103	64.77
Butylene [1]	0.105	68.72
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.88
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.125	71.02
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.54
Heavy Gas Oils	0.148	74.92
Lubricants	0.144	74.27

DEFAULT CO_2 EMISSION FACTORS AND HIGH HEAT VALUES FOR VARIOUS TYPES OF FUEL—Continued

Fuel type	Default high heat value	Default CO_2 emission factor
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.54
Other fuels—solid	mmBtu/short ton	kg CO_2/mmBtu
Municipal Solid Waste	9.95[3]	90.7
Tires	28.00	85.97
Plastics	38.00	75.00
Petroleum Coke	30.00	102.41
Other fuels—gaseous	mmBtu/scf	kg CO_2/mmBtu
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Propane Gas	2.516×10^{-3}	61.46
Fuel Gas[4]	1.388×10^{-3}	59.00
Biomass fuels—solid	mmBtu/short ton	kg CO_2/mmBtu
Wood and Wood Residuals (dry basis)[5]	17.48	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	10.39	105.51
Biomass fuels—gaseous	mmBtu/scf	kg CO_2/mmBtu
Landfill Gas	0.485×10^{-3}	52.07
Other Biomass Gases	0.655×10^{-3}	52.07
Biomass Fuels—Liquid	mmBtu/gallon	kg CO_2/mmBtu
Ethanol	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1] The HHV for components of LPG determined at 60 °F and saturation pressure with the exception of ethylene.

[2] Ethylene HHV determined at 41 °F (5 °C) and saturation pressure.

[3] Use of this default HHV is allowed only for: (a) Units that combust MSW, do not generate steam, and are allowed to use Tier 1; (b) units that derive no more than 10 percent of their annual heat input from MSW and/or tires; and (c) small batch incinerators that combust no more than 1,000 tons of MSW per year.

[4] Reporters subject to subpart X of this part that are complying with § 98.243(d) or subpart Y of this part may only use the default HHV and the default CO_2 emission factor for fuel gas combustion under the conditions prescribed in § 98.243(d)(2)(i) and (d)(2)(ii) and § 98.252(a)(1) and (a)(2), respectively. Otherwise, reporters subject to subpart X or subpart Y shall use either Tier 3 (Equation C–5) or Tier 4.

[5] Use the following formula to calculate a wet basis HHV for use in Equation C–1: $HHV_w = ((100 - M)/100)*HHV_d$ where HHV_w = wet basis HHV, M = moisture content (percent) and HHV_d = dry basis HHV from Table C–1.

[78 FR 71950, Nov. 29, 2013]

TABLE C–2 TO SUBPART C OF PART 98—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C–1)	1.1×10^{-02}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C–1)	3.0×10^{-03}	6.0×10^{-04}
Fuel Gas	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C–1, except wood and wood residuals).	3.2×10^{-02}	4.2×10^{-03}

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Wood and wood residuals	7.2×10^{-03}	3.6×10^{-03}
Biomass Fuels—Gaseous (All fuel types in Table C–1)	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels—Liquid (All fuel types in Table C–1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the ''Energy Industry'' or ''Manufacturing Industries and Construction''. In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC ''Energy Industry'' category may employ a value of 1g of CH_4/mmBtu.

[78 FR 71952, Nov. 29, 2013]

Subpart D—Electricity Generation

§ 98.40 Definition of the source category.

(a) The electricity generation source category comprises electricity generating units that are subject to the requirements of the Acid Rain Program and any other electricity generating units that are required to monitor and report to EPA CO_2 mass emissions year-round according to 40 CFR part 75.

(b) This source category does not include portable equipment, emergency equipment, or emergency generators, as defined in § 98.6.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79155, Dec. 17, 2010]

§ 98.41 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains one or more electricity generating units and the facility meets the requirements of § 98.2(a)(1).

§ 98.42 GHGs to report.

(a) For each electricity generating unit that is subject to the requirements of the Acid Rain Program or is otherwise required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75, you must report under this subpart the annual mass emissions of CO_2, N_2O, and CH_4 by following the requirements of this subpart.

(b) For each electricity generating unit that is not subject to the Acid Rain Program or otherwise required to monitor and report to EPA CO_2 emissions year-round according to 40 CFR part 75, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O by following the requirements of subpart C.

(c) For each stationary fuel combustion unit that does not generate electricity, you must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O by following the requirements of subpart C of this part.

§ 98.43 Calculating GHG emissions.

(a) Except as provided in paragraph (b) of this section, continue to monitor and report CO_2 mass emissions as required under § 75.13 or section 2.3 of appendix G to 40 CFR part 75, and § 75.64. Calculate CO_2, CH_4, and N_2O emissions as follows:

(1) Convert the cumulative annual CO_2 mass emissions reported in the fourth quarter electronic data report required under § 75.64 from units of short tons to metric tons. To convert tons to metric tons, divide by 1.1023.

(2) Calculate and report annual CH_4 and N_2O mass emissions under this subpart by following the applicable method specified in § 98.33(c).

(b) Calculate and report biogenic CO_2 emissions under this subpart by following the applicable methods specified in § 98.33(e). The CO_2 emissions (excluding biogenic CO_2) for units subject to this subpart that are reported under §§ 98.3(c)(4)(i) and (c)(4)(iii)(B) shall be calculated by subtracting the biogenic CO_2 mass emissions calculated according to § 98.33(e) from the cumulative annual CO_2 mass emissions from paragraph (a)(1) of this section. Separate calculation and reporting of biogenic CO_2 emissions is optional only for the 2010 reporting year pursuant to § 98.3(c)(12) and required every year thereafter.

[75 FR 79155, Dec. 17, 2010]

§98.44 Monitoring and QA/QC requirements.

Follow the applicable quality assurance procedures for CO_2 emissions in appendices B, D, and G to 40 CFR part 75.

§98.45 Procedures for estimating missing data.

Follow the applicable missing data substitution procedures in 40 CFR part 75 for CO_2 concentration, stack gas flow rate, fuel flow rate, high heating value, and fuel carbon content.

§98.46 Data reporting requirements.

The annual report shall comply with the data reporting requirements specified in §98.36(d)(1).

[75 FR 79155, Dec. 17, 2010]

§98.47 Records that must be retained.

You shall comply with the recordkeeping requirements of §§98.3(g) and 98.37. Records retained under §75.57(h) of this chapter for missing data events satisfy the recordkeeping requirements of §98.3(g)(4) for those same events.

[75 FR 79155, Dec. 17, 2010]

§98.48 Definitions.

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

Subpart E—Adipic Acid Production

§98.50 Definition of source category.

The adipic acid production source category consists of all adipic acid production facilities that use oxidation to produce adipic acid.

§98.51 Reporting threshold.

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

§98.52 GHGs to report.

(a) You must report N_2O process emissions at the facility level.

(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit following the requirements of subpart C.

§98.53 Calculating GHG emissions.

(a) You must determine annual N_2O emissions from adipic acid production according to paragraphs (a)(1) or (2) of this section.

(1) Use a site-specific emission factor and production data according to paragraphs (b) through (i) of this section.

(2) Request Administrator approval for an alternative method of determining N_2O emissions according to paragraphs (a)(2)(i) and (ii) of this section.

(i) You must submit the request within 45 days following promulgation of this subpart or within the first 30 days of each subsequent reporting year.

(ii) If the Administrator does not approve your requested alternative method within 150 days of the end of the reporting year, you must determine the N_2O emissions for the current reporting period using the procedures specified in paragraphs (b) through (h) of this section.

(b) You must conduct an annual performance test according to paragraphs (b)(1) through (3) of this section.

(1) You must conduct the test on the vent stream from the nitric acid oxidation step of the process, referred to as the test point, according to the methods specified in §98.54(b) through (f). If multiple adipic acid production units exhaust to a common abatement technology and/or emission point, you must sample each process in the ducts before the emissions are combined, sample each process when only one process is operating, or sample the combined emissions when multiple processes are operating and base the site-specific emission factor on the combined production rate of the multiple adipic acid production units.

(2) You must conduct the performance test under normal process operating conditions.

(3) You must measure the adipic acid production rate during the test and calculate the production rate for the test period in tons per hour.

(c) Using the results of the performance test in paragraph (b) of this section, you must calculate an emission factor for each adipic acid unit according to Equation E–1 of this section:

$$EF_{N2O,z} = \frac{\sum_{1}^{n} \frac{C_{N2O} * 1.14 \times 10^{-7} * Q}{P}}{n} \qquad \text{(Eq. E-1)}$$

where:

$EF_{N_2O,z}$ = Average facility-specific N_2O emission factor for each adipic acid production unit ‘‘z’’ (lb N_2O/ton adipic acid produced).

C_{N_2O} = N_2O concentration per test run during the performance test (ppm N_2O).

1.14×10^{-7} = Conversion factor (lb/dscf-ppm N_2O).

Q = Volumetric flow rate of effluent gas per test run during the performance test (dscf/hr).

P = Production rate per test run during the performance test (tons adipic acid produced/hr).

n = Number of test runs.

(d) If the adipic acid production unit exhausts to any N_2O abatement technology ‘‘N’’, you must determine the destruction efficiency according to paragraphs (d)(1), (d)(2), or (d)(3) of this section.

(1) Use the manufacturer's specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge was used to determine the destruction efficiency.

(3) Calculate the destruction efficiency by conducting an additional performance test on the vent stream following the N_2O abatement technology.

(e) If the adipic acid production unit exhausts to any N_2O abatement technology ‘‘N’’, you must determine the annual amount of adipic acid produced while N_2O abatement technology ‘‘N’’ is operating according to §98.54(f). Then you must calculate the abatement factor for N_2O abatement technology ‘‘N’’ according to Equation E–2 of this section.

$$AF_N = \frac{P_{z,N}}{P_z} \qquad \text{(Eq. E-2)}$$

(f) You must determine the annual amount of adipic acid produced according to §98.54(f).

(g) You must calculate N_2O emissions according to paragraph (g)(1), (2), (3), or (4) of this section for each adipic acid production unit.

(1) If one N_2O abatement technology ‘‘N’’ is located after your test point, you must use the emissions factor (determined in Equation E–1 of this section), the destruction efficiency (determined in paragraph (d) of this section), the annual adipic acid production (determined in paragraph (f) of this section), and the abatement utilization factor (determined in paragraph (e) of this section), according to Equation E–3a of this section:

$$E_{a,z} = \frac{EF_{N20,z} * P_z}{2205} * \left(1-\left(DF * AF\right)\right) \qquad \text{(Eq. E-3a)}$$

where:

$E_{a,z}$ = Annual N_2O mass emissions from adipic acid production unit "z" according to this Equation E–3a (metric tons).

EF_{N_2Oz} = N_2O emissions factor for unit "z" (lb N_2O/ton adipic acid produced).

P_z = Annual adipic acid produced from unit "z" (tons).

DF = Destruction efficiency of N_2O abatement technology "N" (decimal fraction of N_2O removed from vent stream).

AF = Abatement utilization factor of N_2O abatement technology "N" (decimal fraction of time that the abatement technology is operating).

2205 = Conversion factor (lb/metric ton).

(2) If multiple N_2O abatement technologies are located in series after your test point, you must use the emissions factor (determined in Equation E–1 of this section), the destruction efficiency (determined in paragraph (d) of this section), the annual adipic acid production (determined in paragraph (f) of this section), and the abatement utilization factor (determined in paragraph (e) of this section), according to Equation E–3b of this section:

$$E_{b,z} = \frac{EF_{N20,z} * P_z}{2205} * (1-(DF_1 * AF_1))* (1-(DF_2 * AF_2))* \ldots * (1-(DF_N * AF_N)) \qquad \text{(Eq. E-3b)}$$

where:

$E_{b,z}$ = Annual N_2O mass emissions from adipic acid production unit "z" according to this Equation E–3b (metric tons).

$EF_{N_2O,z}$ = N_2O emissions factor for unit "z" (lb N_2O/ton adipic acid produced).

P_z = Annual adipic acid produced from unit "z" (tons).

DF_1 = Destruction efficiency of N_2O abatement technology 1 (decimal fraction of N_2O removed from vent stream).

AF_1 = Abatement utilization factor of N_2O abatement technology 1 (decimal fraction of time that abatement technology 1 is operating).

DF_2 = Destruction efficiency of N_2O abatement technology 2 (decimal fraction of N_2O removed from vent stream).

AF_2 = Abatement utilization factor of N_2O abatement technology 2 (decimal fraction of time that abatement technology 2 is operating).

DF_N = Destruction efficiency of N_2O abatement technology "N" (decimal fraction of N_2O removed from vent stream).

AF_N = Abatement utilization factor of N_2O abatement technology "N" (decimal fraction of time that abatement technology N is operating).

2205 = Conversion factor (lb/metric ton).

N = Number of different N_2O abatement technologies.

(3) If multiple N_2O abatement technologies are located in parallel after your test point, you must use the emissions factor (determined in Equation E–1 of this section), the destruction efficiency (determined in paragraph (d) of this section), the annual adipic acid production (determined in paragraph (f) of this section), and the abatement utilization factor (determined in paragraph (e) of this section), according to Equation E–3c of this section:

$$E_{c,z} = \frac{EF_{N20,z} * P_z}{2205} * \sum_{1}^{N} \left(\left(1-\left(DF_N * AF_N\right)\right) * FC_N\right) \qquad \text{(Eq. E-3c)}$$

where:

$E_{c,z}$ = Annual N_2O mass emissions from adipic acid production unit "z" according to this Equation E–3c (metric tons).

$EF_{N_2O,z}$ = N_2O emissions factor for unit ‘‘z’’ (lb N_2O/ton adipic acid produced).

P_z = Annual adipic acid produced from unit ‘‘z’’ (tons).

DF_N = Destruction efficiency of N_2O abatement technology ‘‘N’’ (decimal fraction of N_2O removed from vent stream).

AF_N = Abatement utilization factor of N_2O abatement technology ‘‘N’’ (decimal fraction of time that the abatement technology is operating).

FC_N = Fraction control factor of N_2O abatement technology ‘‘N’’ (decimal fraction of total emissions from unit ‘‘z’’ that are sent to abatement technology ‘‘N’’).

2205 = Conversion factor (lb/metric ton).

N = Number of different N_2O abatement technologies with a fraction control factor.

(4) If no N_2O abatement technologies are located after your test point, you must use the emissions factor (determined using Equation E–1 of this section) and the annual adipic acid production (determined in paragraph (f) of this section) according to Equation E–3d of this section for each adipic acid production unit.

$$E_{d,z} = \frac{EF_{N20} * P_z}{2205} \qquad \text{(Eq. E-3d)}$$

where:

$E_{d,z}$ = Annual N_2O mass emissions from adipic acid production for unit ‘‘z’’ according to this Equation E–3d (metric tons).

EF_{N_2O} = N_2O emissions factor for unit ‘‘z’’ (lb N_2O/ton adipic acid produced).

P_Z = Annual adipic acid produced from unit ‘‘z’’ (tons).

2205 = Conversion factor (lb/metric ton).

(h) You must determine the emissions for the facility by summing the unit level emissions according to Equation E–4 of this section.

$$N_2O = \sum_{z=1}^{M} E_{a,z} + E_{b,z} + E_{c,z} + E_{d,z} \qquad \text{(Eq. E-4)}$$

where:

$E_{a,z}$ = Annual N_2O mass emissions from adipic acid production unit ‘‘z’’ according to Equation E–3a of this section (metric tons).

$E_{b,z}$ = Annual N_2O mass emissions from adipic acid production unit ‘‘z’’ according to Equation E–3b of this section (metric tons).

$E_{c,z}$ = Annual N_2O mass emissions from adipic acid production unit ‘‘z’’ according to Equation E–3c of this section (metric tons).

$E_{d,z}$ = Annual N_2O mass emissions from adipic acid production unit ‘‘z’’ according to Equation E–3d of this section (metric tons).

M = Total number of adipic acid production units.

(i) You must determine the amount of process N_2O emissions that is sold or transferred off site (if applicable). You can determine the amount using existing process flow meters and N_2O analyzers.

[75 FR 66458, Oct. 28, 2010, as amended at 78 FR 71952, Nov. 29, 2013]

§ 98.54 Monitoring and QA/QC requirements.

(a) You must conduct a new performance test and calculate a new emissions factor for each adipic acid production unit according to the frequency specified in paragraphs (a)(1) through (3) of this section.

(1) Conduct the performance test annually. The test must be conducted at a point during production that is representative of the average emissions rate from your process. You must document the methods used to determine the representative point.

(2) Conduct the performance test when your adipic acid production process is changed either by altering the ratio of cyclohexanone to cyclohexanol or by installing abatement equipment.

(3) If you requested Administrator approval for an alternative method of determining N_2O emissions under § 98.53(a)(2), you must conduct the performance test if your request has not been approved by the Administrator within 150 days of the end of the reporting year in which it was submitted.

(b) You must measure the N_2O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

(1) EPA Method 320, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy in 40 CFR part 63, Appendix A;

(2) ASTM D6348–03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy (incorporated by reference, *see* §98.7); or

(3) An equivalent method, with Administrator approval.

(c) You must determine the adipic acid production rate during the performance test according to paragraph (c)(1) or (c)(2) of this section.

(1) Direct measurement (such as using flow meters or weigh scales).

(2) Existing plant procedures used for accounting purposes.

(d) You must determine the volumetric flow rate during the performance test in conjunction with the applicable EPA methods in 40 CFR part 60, appendices A–1 through A–4. Conduct three emissions test runs of 1 hour each. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emissions factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section:

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor.

(3) The production rate(s) during the performance test and how each production rate was determined.

(e) You must determine the monthly amount of adipic acid produced. You must also determine the monthly amount of adipic acid produced during which N_2O abatement technology is operating. These monthly amounts are determined according to the methods in paragraphs (c)(1) or (c)(2) of this section.

(f) You must determine the annual amount of adipic acid produced. You must also determine the annual amount of adipic acid produced during which N_2O abatement technology is operating. These are determined by summing the respective monthly adipic acid production quantities determined in paragraph (e) of this section.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66460, Oct. 28, 2010; 78 FR 71953, Nov. 29, 2013]

§98.55 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of monthly adipic acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the performance test, including emission factors, production rate, and N_2O concentration, you must conduct a new performance test according to the procedures in §98.54 (a) through (d).

§98.56 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (l) of this section at the facility level.

(a) Annual process N_2O emissions from adipic acid production (metric tons).

(b) Annual adipic acid production (tons).

(c) Annual adipic acid production during which N_2O abatement technology (located after the test point) is operating (tons).

(d) Annual process N_2O emissions from adipic acid production facility that is sold or transferred off site (metric tons).

(e) Number of abatement technologies (if applicable).

(f) Types of abatement technologies used (if applicable).

(g) Abatement technology destruction efficiency for each abatement technology (percent destruction).

(h) Abatement utilization factor for each abatement technology (fraction of annual production that abatement technology is operating).

(i) Number of times in the reporting year that missing data procedures were followed to measure adipic acid production (months).

(j) If you conducted a performance test and calculated a site-specific emissions factor according to § 98.53(a)(1), each annual report must also contain the information specified in paragraphs (j)(1) through (7) of this section for each adipic acid production unit.

(1) Emission factor (lb N_2O/ton adipic acid).

(2) Test method used for performance test.

(3) Production rate per test run during performance test (tons/hr).

(4) N_2O concentration per test run during performance test (ppm N_2O).

(5) Volumetric flow rate per test run during performance test (dscf/hr).

(6) Number of test runs.

(7) Number of times in the reporting year that a performance test had to be repeated (number).

(k) If you requested Administrator approval for an alternative method of determining N_2O emissions under § 98.53(a)(2), each annual report must also contain the information specified in paragraphs (k)(1) through (4) of this section for each adipic acid production facility.

(1) Name of alternative method.

(2) Description of alternative method.

(3) Request date.

(4) Approval date.

(l) Fraction control factor for each abatement technology (percent of total emissions from the production unit that are sent to the abatement technology) if equation E–3c is used.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66460, Oct. 28, 2010]

§ 98.57 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the records specified in paragraphs (a) through (h) of this section at the facility level:

(a) Annual adipic acid production capacity (tons).

(b) Records of significant changes to process.

(c) Number of facility and unit operating hours in calendar year.

(d) Documentation of how accounting procedures were used to estimate production rate.

(e) Documentation of how process knowledge was used to estimate abatement technology destruction efficiency.

(f) Performance test reports.

(g) Measurements, records and calculations used to determine reported parameters.

(h) Documentation of the procedures used to ensure the accuracy of the measurements of all reported parameters, including but not limited to, calibration of weighing equipment, flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66461, Oct. 28, 2010]

§ 98.58 Definitions.

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

Subpart F—Aluminum Production

§ 98.60 Definition of the source category.

(a) A primary aluminum production facility manufactures primary aluminum using the Hall-Héroult manufacturing process. The primary aluminum manufacturing process comprises the following operations:

(1) Electrolysis in prebake and Søderberg cells.

(2) Anode baking for prebake cells.

(b) This source category does not include experimental cells or research and development process units.

§ 98.61 Reporting threshold.

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

§ 98.62 GHGs to report.

You must report:

(a) Perfluoromethane (CF_4), and perfluoroethane (C_2F_6) emissions from anode effects in all prebake and Søderberg electrolysis cells.

(b) CO_2 emissions from anode consumption during electrolysis in all prebake and Søderberg electrolysis cells.

(c) CO_2 emissions from on-site anode baking.

(d) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, N_2O, and CH_4 emissions from each stationary fuel combustion unit by following the requirements of subpart C.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79155, Dec. 17, 2010]

§ 98.63 Calculating GHG emissions.

(a) The annual value of each PFC compound (CF_4, C_2F_6) shall be estimated from the sum of monthly values using Equation F–1 of this section:

$$E_{PFC} = \sum_{m=1}^{m=12} E_m \qquad \text{(Eq. F-1)}$$

Where:

E_{PFC} = Annual emissions of each PFC compound from aluminum production (metric tons PFC).

E_m = Emissions of the individual PFC compound from aluminum production for the month ‘‘m’’ (metric tons PFC).

(b) Use Equation F–2 of this section to estimate CF_4 emissions from anode effect duration or Equation F–3 of this section to estimate CF_4 emissions from overvoltage, and use Equation F–4 of this section to estimate C_2F_6 emissions from anode effects from each prebake and Søderberg electrolysis cell.

$$E_{CF4} = S_{CF4} \times AEM \times MP \times 0.001 \qquad \text{(Eq. F-2)}$$

Where:

E_{CF4} = Monthly CF_4 emissions from aluminum production (metric tons CF_4).

S_{CF4} = The slope coefficient ((kg CF_4/metric ton Al)/(AE-Mins/cell-day)).

AEM = The anode effect minutes per cell-day (AE-Mins/cell-day).

MP = Metal production (metric tons Al), where AEM and MP are calculated monthly.

$$E_{CF4} = EF_{CF4} \times MP \times 0.001 \qquad \text{(Eq. F-3)}$$

Where:

E_{CF4} = Monthly CF_4 emissions from aluminum production (metric tons CF_4).

EF_{CF4} = The overvoltage emission factor (kg CF_4/metric ton Al).

MP = Metal production (metric tons Al), where MP is calculated monthly.

$$E_{C2F6} = E_{CF4} \times F_{C2F6/CF4} \times 0.001 \qquad \text{(Eq. F-4)}$$

Where:

E_{C2F6} = Monthly C_2F_6 emissions from aluminum production (metric tons C_2F_6).

E_{CF4} = CF_4 emissions from aluminum production (kg CF_4).

$F_{C2F6/CF4}$ = The weight fraction of C_2F_6/CF_4 (kg C_2F_6/kg CF_4).

0.001 = Conversion factor from kg to metric tons, where E_{CF4} is calculated monthly.

(c) You must calculate and report the annual process CO_2 emissions from anode consumption during electrolysis and anode baking of prebake cells using either the procedures in paragraph (d) of this section, the procedures in paragraphs (e) and (f) of this section, or the procedures in paragraph (g) of this section.

(d) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(e) Use the following procedures to calculate CO_2 emissions from anode consumption during electrolysis:

(1) For Prebake cells: you must calculate CO_2 emissions from anode consumption using Equation F–5 of this section:

$$E_{CO2} = NAC \times MP \times \left(\left[100 - S_a - Ash_a\right]/100\right) \times (44/12) \qquad \text{(Eq. F-5)}$$

Where:

E_{CO2} = Annual CO_2 emissions from prebaked anode consumption (metric tons CO_2).

NAC = Net annual prebaked anode consumption per metric ton Al (metric tons C/metric tons Al).

MP = Annual metal production (metric tons Al).

S_a = Sulfur content in baked anode (percent weight).

Ash_a = Ash content in baked anode (percent weight).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) For Søderberg cells you must calculate CO_2 emissions using Equation F–6 of this section:

$$E_{CO2} = (PC \times MP - \left[CSM \times MP\right]/1000 - BC/100 \times PC \times MP \times \left[S_p + Ash_p + H_p\right]/100 - \left[100 - BC\right]/100 \times PC \times MP \times \left[S_c + Ash_c\right]/100 - MP \times CD) \times (44/12) \qquad \text{(Eq. F-6)}$$

Where:

E_{CO2} = Annual CO_2 emissions from paste consumption (metric ton CO_2).

PC = Annual paste consumption (metric ton/metric ton Al).

MP = Annual metal production (metric ton Al).

CSM = Annual emissions of cyclohexane soluble matter (kg/metric ton Al).

BC = Binder content of paste (percent weight).

S_p = Sulfur content of pitch (percent weight).

Ash_p = Ash content of pitch (percent weight).

H_p = Hydrogen content of pitch (percent weight).

S_c = Sulfur content in calcined coke (percent weight).

Ash_c = Ash content in calcined coke (percent weight).

CD = Carbon in skimmed dust from Søderberg cells (metric ton C/metric ton Al).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(f) Use the following procedures to calculate CO_2 emissions from anode baking of prebake cells:

(1) Use Equation F–7 of this section to calculate emissions from pitch volatiles combustion.

$$E_{CO2PV} = \left(GA - H_w - BA - WT\right) \times (44/12) \qquad \text{(Eq. F-7)}$$

Where:

E_{CO2PV} = Annual CO_2 emissions from pitch volatiles combustion (metric tons CO_2).

GA = Initial weight of green anodes (metric tons).

H_w = Annual hydrogen content in green anodes (metric tons).

BA = Annual baked anode production (metric tons).
WT = Annual waste tar collected (metric tons).
44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) Use Equation F–8 of this section to calculate emissions from bake furnace packing material.

$$E_{CO2PC} = PCC \times BA \times \left(\left[100 - S_{pc} - Ash_{pc}\right]/100\right) \times (44/12) \qquad \text{(Eq. F-8)}$$

Where:

E_{CO2PC} = Annual CO_2 emissions from bake furnace packing material (metric tons CO_2).
PCC = Annual packing coke consumption (metric tons/metric ton baked anode).
BA = Annual baked anode production (metric tons).
S_{pc} = Sulfur content in packing coke (percent weight).
Ash_{pc} = Ash content in packing coke (percent weight).
44/12 = Ratio of molecular weights, CO_2 to carbon.

(g) If process CO_2 emissions from anode consumption during electrolysis or anode baking of prebake cells are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraphs (d) and (e) of this section shall not be used to calculate those process emissions. The owner or operation shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79155, Dec. 17, 2010]

§ 98.64 Monitoring and QA/QC requirements.

(a) Effective December 31, 2010 for smelters with no prior measurement or effective December 31, 2012, for facilities with historic measurements, the smelter-specific slope coefficients, overvoltage emission factors, and weight fractions used in Equations F–2, F–3, and F–4 of this subpart must be measured in accordance with the recommendations of the EPA/IAI Protocol for Measurement of Tetrafluoromethane (CF_4) and Hexafluoroethane (C_2F_6) Emissions from Primary Aluminum Production (2008) (incorporated by reference, see §98.7), except the minimum frequency of measurement shall be every 10 years unless a change occurs in the control algorithm that affects the mix of types of anode effects or the nature of the anode effect termination routine.Facilities which operate at less than 0.2 anode effect minutes per cell day or operate with less than 1.4mV anode effect overvoltage can use either smelter-specific slope coefficients or the technology specific default values in Table F–1 of this subpart.

(b) The minimum frequency of the measurement and analysis is annually except as follows:

(1) Monthly for anode effect minutes per cell day (or anode effect overvoltage and current efficiency).

(2) Monthly for aluminum production.

(3) Smelter-specific slope coefficients, overvoltage emission factors, and weight fractions according to paragraph (a) of this section.

(c) Sources may use either smelter-specific values from annual measurements of parameters needed to complete the equations in §98.63 (e.g., sulfur, ash, and hydrogen contents) or the default values shown in Table F–2 of this subpart.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79155, Dec. 17, 2010]

§ 98.65 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample measurement is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(a) Where anode or paste consumption data are missing, CO_2 emissions can be estimated from aluminum production per Equation F–8 of this section.

$$ECO_2 = EF_p \text{ x } MP_p + EF_s \text{ x } MP_s \qquad \text{(Eq. F-8)}$$

Where:

ECO_2 = CO_2 emissions from anode and/or paste consumption, metric tons CO_2.
EF_p = Prebake technology specific emission factor (1.6 metric tons CO_2/metric ton aluminum produced).
MP_p = Metal production from prebake process (metric tons Al).
EF_s = Søderberg technology specific emission factor (1.7 metric tons CO_2/metric ton Al produced).
MP_s = Metal production from Søderberg process (metric tons Al).

(b) For other parameters, use the average of the two most recent data points after the missing data.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79156, Dec. 17, 2010]

§ 98.66 Data reporting requirements.

In addition to the information required by § 98.3(c), you must report the following information at the facility level:

(a) Annual aluminum production in metric tons.

(b) Type of smelter technology used.

(c) The following PFC-specific information on an annual basis:

(1) Perfluoromethane emissions and perfluoroethane emissions from anode effects in all prebake and all Søderberg electrolysis cells combined.

(2) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), anode effect duration (minutes). (Or anode effect overvoltage factor ((kg CF_4/metric ton Al)/(mV/cell day)), potline overvoltage (mV/cell day), current efficiency (%).)

(3) Smelter-specific slope coefficients (or overvoltage emission factors) and the last date when the smelter-specific-slope coefficients (or overvoltage emission factors) were measured.

(d) Method used to measure the frequency and duration of anode effects (or overvoltage).

(e) The following CO_2-specific information for prebake cells:

(1) Annual anode consumption.

(2) Annual CO_2 emissions from the smelter.

(f) The following CO_2-specific information for Søderberg cells:

(1) Annual paste consumption.

(2) Annual CO_2 emissions from the smelter.

(g) Smelter-specific inputs to the CO_2 process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis.

(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Søderberg) and process control technology (e.g., Pechiney or other).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79156, Dec. 17, 2010]

§ 98.67 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) Monthly aluminum production in metric tons.

(b) Type of smelter technology used.

(c) The following PFC-specific information on a monthly basis:

(1) Perfluoromethane and perfluoroethane emissions from anode effects in prebake and Søderberg electolysis cells.

(2) Anode effect minutes per cell-day (AE-mins/cell-day), anode effect frequency (AE/cell-day), anode effect duration (minutes). (Or anode effect overvoltage factor ((kg CF_4/metric ton Al)/(mV/cell day)), potline overvoltage (mV/cell day), current efficiency (%).))

(3) Smelter-specific slope coefficients and the last date when the smelter-specific-slope coefficients were measured.

(d) Method used to measure the frequency and duration of anode effects (or to measure anode effect overvoltage and current efficiency).

(e) The following CO_2-specific information for prebake cells:

(1) Annual anode consumption.

(2) Annual CO_2 emissions from the smelter.

(f) The following CO_2-specific information for Søderberg cells:

(1) Annual paste consumption.

(2) Annual CO_2 emissions from the smelter.

(g) Smelter-specific inputs to the CO_2 process equations (e.g., levels of sulfur and ash) that were used in the calculation, on an annual basis.

(h) Exact data elements required will vary depending on smelter technology (e.g., point-feed prebake or Søderberg) and process control technology (e.g., Pechiney or other).

§ 98.68 Definitions.

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

TABLE F–1 TO SUBPART F OF PART 98—SLOPE AND OVERVOLTAGE COEFFICIENTS FOR THE CALCULATION OF PFC EMISSIONS FROM ALUMINUM PRODUCTION

Technology	CF_4 slope coefficient [(kg CF_4/metric ton Al)/(AE–Mins/cell-day)]	CF_4 overvoltage coefficient [(kg CF_4/metric ton Al)/(mV)]	Weight fraction C_2F_6/CF_4 [(kg C_2F_6/kg CF_4)]
Center Worked Prebake (CWPB)	0.143	1.16	0.121
Side Worked Prebake (SWPB)	0.272	3.65	0.252
Vertical Stud Søderberg (VSS)	0.092	NA	0.053
Horizontal Stud Søderberg (HSS)	0.099	NA	0.085

[75 FR 79156, Dec. 17, 2010]

TABLE F–2 TO SUBPART F OF PART 98—DEFAULT DATA SOURCES FOR PARAMETERS USED FOR CO_2 EMISSIONS

Parameter	Data source
CO_2 Emissions from Prebake Cells (CWPB and SWPB)	
MP: metal production (metric tons Al)	Individual facility records.
NAC: net annual prebaked anode consumption per metric ton Al (metric tons C/metric tons Al).	Individual facility records.
S_a: sulfur content in baked anode (percent weight)	2.0.
Ash_a: ash content in baked anode (percent weight)	0.4.
CO_2 Emissions From Pitch Volatiles Combustion (CWPB and SWPB)	
MP: metal production (metric tons Al)	Individual facility records.
PC: annual paste consumption (metric ton/metric ton Al)	Individual facility records.
CSM: annual emissions of cyclohexane soluble matter (kg/metric ton Al)	HSS: 4.0. VSS: 0.5.
BC: binder content of paste (percent weight)	Dry Paste: 24. Wet Paste: 27.
S_p: sulfur content of pitch (percent weight)	0.6.
Ash_p: ash content of pitch (percent weight)	0.2.
H_p: hydrogen content of pitch (percent weight)	3.3.
S_c: sulfur content in calcined coke (percent weight)	1.9.
Ash_c: ash content in calcined coke (percent weight)	0.2.
CD: carbon in skimmed dust from Søderberg cells (metric ton C/metric ton Al)	0.01.
CO_2 Emissions from Pitch Volatiles Combustion (VSS and HSS)	
GA: initial weight of green anodes (metric tons)	Individual facility records.
H_w: annual hydrogen content in green anodes (metric tons)	0.005 × GA.
BA: annual baked anode production (metric tons)	Individual facility records.
WT: annual waste tar collected (metric tons) (a) Riedhammer furnaces (b) all other furnaces.	(a) 0.005 × GA. (b) insignificant.

Parameter	Data source
CO_2 Emissions From Bake Furnace Packing Materials (CWPB and SWPB)	
PCC: annual packing coke consumption (metric tons/metric ton baked anode)	0.015.
BA: annual baked anode production (metric tons)	Individual facility records.
S_{pc}: sulfur content in packing coke (percent weight)	2.
Ash_{pc}: ash content in packing coke (percent weight)	2.5.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79156, Dec. 17, 2010]

Subpart G—Ammonia Manufacturing

§ 98.70 Definition of source category.

The ammonia manufacturing source category comprises the process units listed in paragraphs (a) and (b) of this section.

(a) Ammonia manufacturing processes in which ammonia is manufactured from a fossil-based feedstock produced via steam reforming of a hydrocarbon.

(b) Ammonia manufacturing processes in which ammonia is manufactured through the gasification of solid and liquid raw material.

§ 98.71 Reporting threshold.

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

§ 98.72 GHGs to report.

You must report:

(a) CO_2 process emissions from steam reforming of a hydrocarbon or the gasification of solid and liquid raw material, reported for each ammonia manufacturing process unit following the requirements of this subpart (CO_2 process emissions reported under this subpart may include CO_2 that is later consumed on site for urea production, and therefore is not released to the ambient air from the ammonia manufacturing process unit).

(b) CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources), by following the requirements of subpart C, except that for ammonia manufacturing processes subpart C does not apply to any CO_2 resulting from combustion of the waste recycle stream (commonly referred to as the purge gas stream).

(c) CO_2 emissions collected and transferred off site under subpart PP of this part (Suppliers of CO_2), following the requirements of subpart PP.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79156, Dec. 17, 2010]

§ 98.73 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each ammonia manufacturing process unit using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to 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).

(b) Calculate and report under this subpart process CO_2 emissions using the procedures in paragraphs (b)(1) through (b)(5) of this section for gaseous feedstock, liquid feedstock, or solid feedstock, as applicable.

(1) *Gaseous feedstock*. You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from gaseous feedstock according to Equation G–1 of this section:

$$CO_{2,G,k} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_{n,k} * CC_n * \frac{MW}{MVC} \right) * 0.001 \qquad \text{(Eq. G-1)}$$

Where:

$CO_{2,G,k}$ = Annual CO_2 emissions arising from gaseous feedstock consumption (metric tons).

$Fdstk_n$ = Volume of the gaseous feedstock used in month n (scf of feedstock).

CC_n = Carbon content of the gaseous feedstock, for month n (kg C per kg of feedstock), determined according to 98.74(c).

MW = Molecular weight of the gaseous feedstock (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

k = Processing unit.

n = Number of month.

(2) *Liquid feedstock.* You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from liquid feedstock according to Equation G–2 of this section:

$$CO_{2,L,k} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_{n,k} * CC_n \right) * 0.001 \qquad \text{(Eq. G-2)}$$

Where:

$CO_{2,L,k}$ = Annual CO_2 emissions arising from liquid feedstock consumption (metric tons).

$Fdstk_n$ = Volume of the liquid feedstock used in month n (gallons of feedstock).

CC_n = Carbon content of the liquid feedstock, for month n (kg C per gallon of feedstock) determined according to 98.74(c).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

k = Processing unit.

n = Number of month.

(3) *Solid feedstock.* You must calculate, from each ammonia manufacturing unit, the CO_2 process emissions from solid feedstock according to Equation G–3 of this section:

$$CO_{2,S,k} = \left(\sum_{n=1}^{12} \frac{44}{12} * Fdstk_{n,k} * CC_n \right) * 0.001 \qquad \text{(Eq. G-3)}$$

Where:

$CO_{2,S,k}$ = Annual CO_2 emissions arising from solid feedstock consumption (metric tons).

$Fdstk_n$ = Mass of the solid feedstock used in month n (kg of feedstock).

CC_n = Carbon content of the solid feedstock, for month n (kg C per kg of feedstock), determined according to 98.74(c).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

k = Processing unit.

n = Number of month.

(4) You must calculate the annual process CO_2 emissions from each ammonia processing unit k at your facility according to Equation G–4 of this section:

$$E_{CO2,k} = CO_{2,G,k} + CO_{2,L,k} + CO_{2,S,k} \quad \text{(Eq. G-4)}$$

Where:

E_{CO2_k} = Annual CO_2 emissions from each ammonia processing unit k (metric tons).

k = Processing unit.

(5) You must determine the combined CO_2 emissions from all ammonia processing units at your facility using Equation G–5 of this section.

$$CO_2 = \sum_{k=1}^{n} E_{CO2_k} \quad \text{(Eq. G-5)}$$

Where:

CO_2 = Annual combined CO_2 emissions from all ammonia processing units (metric tons) (CO_2 process emissions reported under this subpart may include CO_2 that is later consumed on site for urea production, and therefore is not released to the ambient air from the ammonia manufacturing process unit(s)).

E_{CO2_k} = Annual CO_2 emissions from each ammonia processing unit (metric tons).

k = Processing unit.

n = Total number of ammonia processing units.

(c) If GHG emissions from an ammonia manufacturing unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79156, Dec. 17, 2010]

§ 98.74 Monitoring and QA/QC requirements.

(a) You must continuously measure the quantity of gaseous or liquid feedstock consumed using a flow meter. The quantity of solid feedstock consumed can be obtained from company records and aggregated on a monthly basis.

(b) You must document the procedures used to ensure the accuracy of the estimates of feedstock consumption.

(c) You must determine monthly carbon contents and the average molecular weight of each feedstock consumed from reports from your supplier. As an alternative to using supplier information on carbon contents, you can also collect a sample of each feedstock on a monthly basis and analyze the carbon content and molecular weight of the fuel using any of the following methods listed in paragraphs (c)(1) through (c)(8) of this section, as applicable.

(1) ASTM D1945–03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(2) ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(3) ASTM D2502–04 (Reapproved 2002) Standard Test Method for Estimation of Mean Relative Molecular Mass of Petroleum Oils from Viscosity Measurements (incorporated by reference, *see* § 98.7).

(4) 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).

(5) ASTM D3238–95 (Reapproved 2005) Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, *see* § 98.7).

(6) 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).

(7) ASTM D3176–89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, *see* § 98.7).

(8) ASTM D5373–08 Standard Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal (incorporated by reference, *see* § 98.7).

(d) Calibrate all oil and gas flow meters that are used to measure liquid and gaseous feedstock volumes and flow rates (except for gas billing meters) according to the monitoring and QA/QC requirements for the Tier 3 methodology in § 98.34(b)(1). Perform oil tank drop measurements (if used to quantify feedstock volumes) according to § 98.34(b)(2).

(e) For quality assurance and quality control of the supplier data, on an annual basis, you must measure the carbon contents of a representative sample of the feedstocks consumed using the appropriate ASTM Method as listed in paragraphs (c)(1) through (c)(8) of this section.

(f) [Reserved]

(g) If CO_2 from ammonia production is used to produce urea at the same facility, you must determine the quantity of urea produced using methods or plant instruments used for accounting purposes (such as sales records). You must document the procedures used to ensure the accuracy of the estimates of urea produced.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79156, Dec. 17, 2010]

§ 98.75 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever the monitoring and quality assurance procedures in § 98.74 cannot be followed (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter shall be used in the calculations following paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing data on monthly carbon contents of feedstock, the substitute data value shall be the arithmetic average of the quality-assured values of that carbon content in the month preceding and the month immediately following the missing data incident. If no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon content obtained in the month after the missing data period.

(b) For missing feedstock supply rates used to determine monthly feedstock consumption, you must determine the best available estimate(s) of the parameter(s), based on all available process data.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79157, Dec. 17, 2010; 78 FR 71953, Nov. 29, 2013]

§ 98.76 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as applicable for each ammonia manufacturing process unit.

(a) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under § 98.36 for the Tier 4 Calculation Methodology and the information in paragraphs (a)(1) and (2) of this section:

(1) Annual quantity of each type of feedstock consumed for ammonia manufacturing (scf of feedstock or gallons of feedstock or kg of feedstock).

(2) Method used for determining quantity of feedstock used.

(b) If a CEMS is not used to measure emissions, then you must report all of the following information in this paragraph (b):

(1) Annual CO_2 process emissions (metric tons) for each ammonia manufacturing process unit.

(2) Monthly quantity of each type of feedstock consumed for ammonia manufacturing for each ammonia processing unit (scf of feedstock or gallons of feedstock or kg of feedstock).

(3) Method used for determining quantity of monthly feedstock used.

(4) Whether carbon content for each feedstock for month n is based on reports from the supplier or analysis of carbon content.

(5) If carbon content of feedstock for month n is based on analysis, the test method used.

(6) Sampling analysis results of carbon content of feedstock as determined for QA/QC of supplier data under § 98.74(e).

(7) If a facility uses gaseous feedstock, the carbon content of the gaseous feedstock, for month n, (kg C per kg of feedstock).

(8) If a facility uses gaseous feedstock, the molecular weight of the gaseous feedstock (kg/kg-mole).

(9) If a facility uses gaseous feedstock, the molar volume conversion factor of the gaseous feedstock (scf per kg-mole).

(10) If a facility uses liquid feedstock, the carbon content of the liquid feedstock, for month n, (kg C per gallon of feedstock).

(11) If a facility uses solid feedstock, the carbon content of the solid feedstock, for month n, (kg C per kg of feedstock).

(12) Annual urea production (metric tons) and method used to determine urea production.

(13) Annual CO_2 emissions (metric tons) from the steam reforming of a hydrocarbon or the gasification of solid and liquid raw material at the ammonia manufacturing process unit used to produce urea and the method used to determine the CO_2 consumed in urea production.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79157, Dec. 17, 2010; 78 FR 71953, Nov. 29, 2013]

§ 98.77 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the following records specified in paragraphs (a) and (b) of this section for each ammonia manufacturing unit.

(a) If a CEMS is used to measure emissions, retain records of all feedstock purchases in addition to the requirements in § 98.37 for the Tier 4 Calculation Methodology.

(b) If a CEMS is not used to measure process CO_2 emissions, you must also retain the records specified in paragraphs (b)(1) through (b)(2) of this section:

(1) Records of all analyses and calculations conducted for reported data as listed in § 98.76(b).

(2) Monthly records of carbon content of feedstock from supplier and/or all analyses conducted of carbon content.

§ 98.78 Definitions.

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

Subpart H—Cement Production

§ 98.80 Definition of the source category.

The cement production source category consists of each kiln and each inline kiln/raw mill at any portland cement manufacturing facility including alkali bypasses, and includes kilns and in-line kiln/raw mills that burn hazardous waste.

§ 98.81 Reporting threshold.

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

§ 98.82 GHGs to report.

You must report:

(a) CO_2 process emissions from calcination in each kiln.

(b) CO_2 combustion emissions from each kiln.

(c) CH_4 and N_2O combustion emissions from each kiln. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than kilns. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.83 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each kiln using the procedure in paragraphs (a) and (b) of this section.

(a) For each cement kiln that meets the conditions specified in § 98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report under this subpart the combined process and combustion

CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to 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).

(b) For each kiln that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO_2 emissions from the kiln by using the procedure in either paragraph (c) or (d) of this section.

(c) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to 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).

(d) Calculate and report process and combustion CO_2 emissions separately using the procedures specified in paragraphs (d)(1) through (d)(4) of this section.

(1) Calculate CO_2 process emissions from all kilns at the facility using Equation H–1 of this section:

$$CO_{2CMF} = \sum_{m=1}^{k} CO_{2Cli,m} + CO_{2rm} \qquad \text{(Eq. H-1)}$$

Where:

$CO_{2\ CMF}$ = Annual process emissions of CO_2 from cement manufacturing, metric tons.

$CO_{2\ Cli,m}$ = Total annual emissions of CO_2 from clinker production from kiln m, metric tons.

$CO_{2\ rm}$ = Total annual emissions of CO_2 from raw materials, metric tons.

k = Total number of kilns at a cement manufacturing facility.

(2) *CO_2 emissions from clinker production.* Calculate CO_2 emissions from each kiln using Equations H–2 through H–5 of this section.

$$CO_{2\ Cli,m} = \sum_{j=1}^{p}\left[\left(Cli,_{j}\right)*\left(EF_{Cli,j}\right)*\frac{2000}{2205}\right] + \sum_{i=1}^{r}\left[\left(CKD,_{i}\right)*\left(EF_{CKD,i}\right)*\frac{2000}{2205}\right] \qquad \text{(Eq. H-2)}$$

Where:

$Cli,_j$ = Quantity of clinker produced in month j from kiln m, tons.

$EF_{Cli,j}$ = Kiln specific clinker emission factor for month j for kiln m, metric tons CO_2/metric ton clinker computed as specified in Equation H–3 of this section.

$CKD,_i$ = Cement kiln dust (CKD) not recycled to the kiln in quarter i from kiln m, tons.

$EF_{CKD,i}$ = Kiln specific CKD emission factor for quarter i from kiln m, metric tons CO_2/metric ton CKD computed as specified in Equation H–4 of this section.

p = Number of months for clinker calculation, 12.

r = Number of quarters for CKD calculation, 4.

2000/2205 = Conversion factor to convert tons to metric tons.

(i) *Kiln-Specific Clinker Emission Factor.* (A) Calculate the kiln-specific clinker emission factor using Equation H–3 of this section.

$$EF_{\mathrm{Cli}} = \left(CLi_{CaO} - Cli_{ncCaO}\right)*MR_{CaO} + \left(Cli_{MgO} - Cli_{ncMgO}\right)*MR_{MgO} \qquad \text{(Eq. H-3)}$$

Where:

Cli_{CaO} = Monthly total CaO content of Clinker, wt-fraction.

Cli_{ncCaO} = Monthly non-calcined CaO content of Clinker, wt-fraction.

MR_{CaO} = Molecular-weight Ratio of CO_2/CaO = 0.785.

Cli_{MgO} = Monthly total MgO content of Clinker, wt-fraction.

Cli_{ncMgO} = Monthly non-calcined MgO content of Clinker, wt-fraction.

MR_{MgO} = Molecular-weight Ratio of CO_2/MgO = 1.092.

(B) Non-calcined CaO is CaO that remains in the clinker in the form of $CaCO_3$ and CaO in the clinker that entered the kiln as a non-carbonate species. Non-calcined MgO is MgO that remains in the clinker in the form of $MgCO_3$ and MgO in the clinker that entered the kiln as a non-carbonate species.

(ii) *Kiln-Specific CKD Emission Factor.* (A) Calculate the kiln-specific CKD emission factor for CKD not recycled to the kiln using Equation H–4 of this section.

$$EF_{\mathrm{CKD}} = \left(CKD_{CaO} - CKD_{ncCaO}\right) * MR_{CaO} + \left(CKD_{MgO} - CKD_{ncMgO}\right) * MR_{MgO} \qquad \text{(Eq. H-4)}$$

Where:

CKD_{CaO} = Quarterly total CaO content of CKD not recycled to the kiln, wt-fraction.

CKD_{CaO} = Quarterly non-calcined CaO content of CKD not recycled to the kiln, wt-fraction.

MR_{CaO} = Molecular-weight Ratio of CO_2/CaO = 0.785.

CKD_{MgO} = Quarterly total MgO content of CKD not recycled to the kiln, wt-fraction.

CKD_{MgO} = Quarterly non-calcined MgO content of CKD not recycled to the kiln, wt-fraction.

MR_{MgO} = Molecular-weight Ratio of CO_2/MgO = 1.092.

(B) Non-calcined CaO is CaO that remains in the CKD in the form of $CaCO_3$ and CaO in the CKD that entered the kiln as a non-carbonate species. Non-calcined MgO is MgO that remains in the CKD in the form of $MgCO_3$ and MgO in the CKD that entered the kiln as a non-carbonate species.

(3) *CO_2 emissions from raw materials.* Calculate CO_2 emissions from raw materials using Equation H–5 of this section:

$$CO_{2,rm} = \sum_{i=1}^{m} rm \, * \, TOCrm \, * \frac{44}{12} * \frac{2000}{2205} \qquad \text{(Eq. H-5)}$$

Where:

rm = The amount of raw material i consumed annually, tons/yr (dry basis) or the amount of raw kiln feed consumed annually, tons/yr (dry basis).

$CO_{2,rm}$ = Annual CO_2 emissions from raw materials.

TOCrm = Organic carbon content of raw material i or organic carbon content of combined raw kiln feed (dry basis), as determined in § 98.84(c) or using a default factor of 0.2 percent of total raw material weight.

M = Number of raw materials or 1 if calculating emissions based on combined raw kiln feed.

44/12 = Ratio of molecular weights, CO_2 to carbon.

2000/2205 = Conversion factor to convert tons to metric tons.

(4) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions from the kiln according to the applicable requirements in subpart C.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66461, Oct. 28, 2010]

§ 98.84 Monitoring and QA/QC requirements.

(a) You must determine the weight fraction of total CaO and total MgO in

CKD not recycled to the kiln from each kiln using ASTM C114–09, Standard Test Methods for Chemical Analysis of Hydraulic Cement (incoporated by reference, see § 98.7). The monitoring must be conducted quarterly for each kiln from a CKD sample drawn either as CKD is exiting the kiln or from bulk CKD storage.

(b) You must determine the weight fraction of total CaO and total MgO in clinker from each kiln using ASTM C114–09 Standard Test Methods for Chemical Analysis of Hydraulic Cement (incorporated by reference, see § 98.7). The monitoring must be conducted monthly for each kiln from a monthly clinker sample drawn from bulk clinker storage if storage is dedicated to the specific kiln, or from a monthly arithmetic average of daily clinker samples drawn from the clinker conveying systems exiting each kiln.

(c) The total organic carbon content (dry basis) of raw materials must be determined annually using ASTM C114–09 Standard Test Methods for Chemical Analysis of Hydraulic Cement (incorporated by reference, see § 98.7) or a similar industry standard practice or method approved for total organic carbon determination in raw mineral materials. The analysis must be conducted either on sample material drawn from bulk raw kiln feed storage or on sample material drawn from bulk raw material storage for each category of raw material (i.e., limestone, sand, shale, iron oxide, and alumina). Facilities that opt to use the default total organic carbon factor provided in § 98.83(d)(3), are not required to monitor for TOC.

(d) The quantity of clinker produced monthly by each kiln must be determined by direct weight measurement of clinker using the same plant techniques used for accounting purposes, such as reconciling weigh hopper or belt weigh feeder measurements against inventory measurements. As an alternative, facilities may also determine clinker production by direct measurement of raw kiln feed and application of a kiln-specific feed-to-clinker factor. Facilities that opt to use a feed-to-clinker factor must verify the accuracy of this factor on a monthly basis.

(e) The quantity of CKD not recycled to the kiln generated by each kiln must be determined quarterly using the same plant techniques used for accounting purposes, such as direct weight measurement using weigh hoppers, truck weigh scales, or belt weigh feeders.

(f) The annual quantity of raw kiln feed or annual quantity of each category of raw materials consumed by the facility (e.g., limestone, sand, shale, iron oxide, and alumina) must be determined monthly by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers, truck weigh scales, or belt weigh feeders.

(g) The monthly non-calcined CaO and MgO that remains in the clinker in the form of $CaCO_3$ or that enters the kiln as a non-carbonate species may be assumed to be a default value of 0.0 or may be determined monthly by careful chemical analysis of feed material and clinker material from each kiln using well documented analytical and calculational methods or the appropriate industry standard practice.

(h) The quarterly non-calcined CaO and MgO that remains in the CKD in the form of $CaCO_3$ or that enters the kiln as a non-carbonate species may be assumed to be a default value of 0.0 or may be determined quarterly by careful chemical analysis of feed material and CKD material from each kiln using well documented analytical and calculational methods or the appropriate industry standard practice.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66461, Oct. 28, 2010]

§ 98.85 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in § 98.83 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations. The owner or operator must document and keep records of the procedures used for all such estimates.

(a) If the CEMS approach is used to determine combined process and combustion CO_2 emissions, the missing data procedures in § 98.35 apply.

(b) For CO_2 process emissions from cement manufacturing facilities calculated according to § 98.83(d), if data on the carbonate content (of clinker or CKD), noncalcined content (of clinker or CKD) or the annual organic carbon content of raw materials are missing, facilities must undertake a new analysis.

(c) For each missing value of monthly clinker production the substitute data value must be the best available estimate of the monthly clinker production based on information used for accounting purposes, or use the maximum tons per day capacity of the system and the number of days per month.

(d) For each missing value of monthly raw material consumption the substitute data value must be the best available estimate of the monthly raw material consumption based on information used for accounting purposes (such as purchase records), or use the maximum tons per day raw material throughput of the kiln and the number of days per month.

§ 98.86 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as appropriate.

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required by § 98.36(e)(2)(vi) and the information listed in this paragraph(a):

(1) Monthly clinker production from each kiln at the facility.

(2) Annual facility cement production.

(3) Number of kilns and number of operating kilns.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in this paragraph (b) for each kiln:

(1) Kiln identification number.

(2) Monthly clinker production from each kiln.

(3) Annual cement production at the facility.

(4) Number of kilns and number of operating kilns.

(5) Quarterly quantity of CKD not recycled to the kiln for each kiln at the facility.

(6) Monthly fraction of total CaO, total MgO, non-calcined CaO and non-calcined MgO in clinker for each kiln (as wt-fractions).

(7) Method used to determine non-calcined CaO and non-calcined MgO in clinker.

(8) Quarterly fraction of total CaO, total MgO, non-calcined CaO and non-calcined MgO in CKD not recycled to the kiln for each kiln (as wt-fractions).

(9) Method used to determine non-calcined CaO and non-calcined MgO in CKD.

(10) Monthly kiln-specific clinker CO_2 emission factors for each kiln (metric tons CO_2/metric ton clinker produced).

(11) Quarterly kiln-specific CKD CO_2 emission factors for each kiln (metric tons CO_2/metric ton CKD produced).

(12) Annual organic carbon content of raw kiln feed or annual organic carbon content of each raw material (wt-fraction, dry basis).

(13) Annual consumption of raw kiln feed or annual consumption of each raw material (dry basis).

(14) Number of times missing data procedures were used to determine the following information:

(i) Clinker production (number of months).

(ii) Carbonate contents of clinker (number of months).

(iii) Non-calcined content of clinker (number of months).

(iv) CKD not recycled to kiln (number of quarters).

(v) Non-calcined content of CKD (number of quarters)

(vi) Organic carbon contents of raw materials (number of times).

(vii) Raw material consumption (number of months).

(15) Method used to determine the monthly clinker production from each kiln reported under (b)(2) of this section, including monthly kiln-specific clinker factors, if used.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66461, Oct. 28, 2010; 78 FR 71953, Nov. 29, 2013]

§ 98.87 Records that must be retained.

(a) If a CEMS is used to measure CO_2 emissions, then in addition to the records required by § 98.3(g), you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37.

(b) If a CEMS is not used to measure CO_2 emissions, then in addition to the records required by § 98.3(g), you must retain the records specified in this paragraph (b) for each portland cement manufacturing facility.

(1) Documentation of monthly calculated kiln-specific clinker CO_2 emission factor.

(2) Documentation of quarterly calculated kiln-specific CKD CO_2 emission factor.

(3) Measurements, records and calculations used to determine reported parameters.

[75 FR 66461, Oct. 28, 2010]

§ 98.88 Definitions.

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

Subpart I—Electronics Manufacturing

SOURCE: 75 FR 74818, Dec. 1, 2010, unless otherwise noted.

§ 98.90 Definition of the source category.

(a) The electronics manufacturing source category consists of any of the production processes listed in paragraphs (a)(1) through (a)(5) of this section that use fluorinated GHGs or N_2O. Facilities that may use these processes include, but are not limited to, facilities that manufacture micro-electro-mechanical systems (MEMS), liquid crystal displays (LCDs), photovoltaic cells (PV), and semiconductors (including light-emitting diodes (LEDs)).

(1) Any electronics production process in which the etching process uses plasma-generated fluorine atoms and other reactive fluorine-containing fragments, that chemically react with exposed thin-films (e.g., dielectric, metals) or substrate (e.g., silicon) to selectively remove portions of material.

(2) Any electronics production process in which chambers used for depositing thin films are cleaned periodically using plasma-generated fluorine atoms and other reactive fluorine-containing fragments.

(3) Any electronics production process in which wafers are cleaned using plasma generated fluorine atoms or other reactive fluorine-containing fragments to remove residual material from wafer surfaces, including the wafer edge.

(4) Any electronics production process in which the chemical vapor deposition (CVD) process or other manufacturing processes use N_2O.

(5) Any electronics manufacturing production process in which fluorinated heat transfer fluids are used to cool process equipment, to control temperature during device testing, to clean substrate surfaces and other parts, and for soldering (e.g., vapor phase reflow).

[75 FR 74818, Dec. 1, 2010, as amended at 77 FR 10380, Feb. 22, 2012]

§ 98.91 Reporting threshold.

(a) You must report GHG emissions under this subpart if electronics manufacturing production processes, as defined in § 98.90, are performed at your facility and your facility meets the requirements of either § 98.2(a)(1) or (a)(2). To calculate total annual GHG emissions for comparison to the 25,000 metric ton CO_2e per year emission threshold in § 98.2(a)(2), follow the requirements of § 98.2(b), with one exception. Rather than using the calculation methodologies in § 98.93 to calculate emissions from electronics manufacturing production processes, calculate emissions of each fluorinated GHG from electronics manufacturing production processes by using paragraphs (a)(1), (a)(2), or (a)(3) of this section, as appropriate, and then sum the emissions of each fluorinated GHG by using paragraph (a)(4) of this section.

(1) If you manufacture semiconductors or MEMS you must calculate annual production process emissions of each input gas i for threshold applicability purposes using the default emission factors shown in Table I–1 to this subpart and Equation I–1 of this subpart.

$$\mathrm{E_i} = S * \mathrm{EF_i} * GWP_i * 0.001 \quad \text{(Eq. I-1)}$$

where:

E_i = Annual production process emissions of input gas i for threshold applicability purposes (metric tons CO_2e).

S = 100 percent of annual manufacturing capacity of a facility as calculated using Equation I–5 of this subpart (m^2).

EF_i = Emission factor for input gas i (kg/m^2).

GWP_i = Gas-appropriate GWP as provided in Table A–1 to subpart A of this part.

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

(2) If you manufacture LCDs, you must calculate annual production process emissions of each input gas i for threshold applicability purposes using the default emission factors shown in Table I–1 to this subpart and Equation I–2 of this subpart.

$$\mathrm{E_i} = S * \mathrm{EF_i} * GWP_i * 0.000001 \quad \text{(Eq. I-2)}$$

where:

E_i = Annual production process emissions of input gas i for threshold applicability purposes (metric tons Co_2e).

S = 100 percent of annual manufacturing capacity of a facility as calculated using Equation I–5 of this subpart (m^2).

EF_i = Emission factor for input gas i (g/m^2).

GWP_i = Gas-appropriate GWP as provided in Table A–1 to subpart A of this part.

0.000001 = Conversion factor from g to metric tons.

i = Input gas.

(3) If you manufacture PVs, you must calculate annual production process emissions of each input gas i for threshold applicability purposes using gas-appropriate GWP values shown in Table A–1 to subpart A of this part and Equation I–3 of this subpart.

$$\mathrm{E_i} = C_i * GWP_i * 0.001 \quad \text{(Eq. I-3)}$$

where:

E_i = Annual production process emissions of input gas i for threshold applicability purposes (metric tons Co_2e).

C_i = Annual fluorinated GHG (input gas i) purchases or consumption (kg). Only gases that are used in PV manufacturing processes listed at §98.90(a)(1) through (a)(4) that have listed GWP values in Table A–1 to subpart A of this part must be considered for threshold applicability purposes.

GWP_i = Gas-appropriate GWP as provided in Table A–1 to subpart A of this part.

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

(4) You must calculate total annual production process emissions for threshold applicability purposes using Equation I–4 of this subpart.

$$\mathrm{E_T} = \delta * \sum_i E_i \quad \text{(Eq. I-4)}$$

where:

E_T = Annual production process emissions of all fluorinated GHGs for threshold applicability purposes (metric tons Co_2e).

δ = Factor accounting for fluorinated heat transfer fluid emissions, estimated as 10 percent of total annual production process emissions at a semiconductor facility. Set equal to 1.1 when Equation I–4 of this subpart is used to calculate total annual production process emissions from semiconductor manufacturing. Set equal to 1 when Equation I–4 of this subpart is used to calculate total annual production process emissions from MEMS, LCD, or PV manufacturing.

E_i = Annual production process emissions of input gas i for threshold applicability purposes (metric tons Co_2e), as calculated in Equations I–1, I–2 or I–3 of this subpart.

i = Input gas.

(b) You must calculate annual manufacturing capacity of a facility using Equation I–5 of this subpart.

$$S = \sum_{x}^{12} W_x \quad \text{(Eq. I-5)}$$

where:

S = 100 percent of annual manufacturing capacity of a facility (m^2).

W_X = Maximum substrate starts of fab f in month x (m^2 per month).

x = Month.

[75 FR 74818, Dec. 1, 2010, as amended at 77 FR 10380, Feb. 22, 2012; 78 FR 68202, Nov. 13, 2013]

§98.92 GHGs to report.

(a) You must report emissions of fluorinated GHGs (as defined in §98.6), N_2O, and fluorinated heat transfer fluids (as defined in §98.98). The fluorinated GHGs and fluorinated heat transfer fluids that are emitted from electronics manufacturing production processes include, but are not limited to, those listed in Table I–2 to this subpart. You must individually report, as appropriate:

(1) Fluorinated GHGs emitted.

(2)–(3) [Reserved]

(4) N_2O emitted from chemical vapor deposition and other electronics manufacturing processes.

(5) Emissions of fluorinated heat transfer fluids.

(6) All fluorinated GHGs and N_2O consumed.

(b) CO_2, CH_4, and N_2O combustion emissions from each stationary combustion unit. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C of this part.

[75 FR 74818, Dec. 1, 2010, as amended at 77 FR 10380, Feb. 22, 2012; 78 FR 68202, Nov. 13, 2013]

§98.93 Calculating GHG emissions.

(a) You must calculate total annual emissions of each fluorinated GHG emitted by electronics manufacturing production processes from each fab (as defined in §98.98) at your facility, including each input gas and each by-product gas. You must use either default gas utilization rates and by-product formations rates according to the procedures in paragraph (a)(1), (a)(2), or (a)(6) of this section, as appropriate, or the stack test method according to paragraph (i) of this section, to calculate emissions of each input gas and each by-product gas.

(1) If you manufacture semiconductors, you must adhere to the procedures in paragraphs (a)(2)(i) through (iii) of this section. You must calculate annual emissions of each input gas and of each by-product gas using Equations I–6 and I–7, respectively. If your fab uses less than 50 kg of a fluorinated GHG in one reporting year, you may calculate emissions as equal to your fab's annual consumption for that specific gas as calculated in Equation I–11 of this subpart, plus any by-product emissions of that gascalculated under this paragraph (a).

$$\Pr ocesstypeE_{i} = \sum_{j=1}^{N} E_{ij} \qquad \text{(Eq. I-6)}$$

Where:

ProcesstypeE$_i$ = Annual emissions of input gas i from the process type on a fab basis (metric tons).

E$_{ij}$ = Annual emissions of input gas i from process sub-type or process type j as calculated in Equation I–8 of this subpart (metric tons).

N = The total number of process sub-types j that depends on the electronics manufacturing fab and emission calculation methodology. If E$_{ij}$ is calculated for a process type j in Equation I–8 of this subpart, N = 1.

i = Input gas.

j = Process sub-type or process type.

$$\Pr ocesstypeBE_{k} = \sum_{j=1}^{N} \sum_{i} BE_{ijk} \qquad \text{(Eq. I-7)}$$

Where:

ProcesstypeBE$_k$ = Annual emissions of by-product gas k from the processes type on a fab basis (metric tons).

BE$_{ijk}$ = Annual emissions of by-product gas k formed from input gas i used for process sub-type or process type j as calculated in Equation I–9 of this subpart (metric tons).

N = The total number of process sub-types j that depends on the electronics manufacturing fab and emission calculation methodology. If BE$_{ijk}$ is calculated for a process type j in Equation I–9 of this subpart, N = 1.

i = Input gas.

j = Process sub-type, or process type.

k = By-product gas.

(i) You must calculate annual fab-level emissions of each fluorinated GHG used for the plasma etching/wafer cleaning process type using default utilization and by-product formation rates as shown in Table I–3 or I–4 of this subpart, and by using Equations I–8 and I–9 of this subpart.

$$E_{ij} = C_{ij} * (1 - U_{ij}) * \left(1 - (a_{ij} * d_{ij} * UT_{ij})\right) * 0.001 \qquad \text{(Eq. I-8)}$$

Where:

E$_{ij}$ = Annual emissions of input gas i from process sub-type or process type j, on a fab basis (metric tons).

C$_{ij}$ = Amount of input gas i consumed for process sub-type or process type j, as calculated in Equation I–13 of this subpart, on a fab basis (kg).

U$_{ij}$ = Process utilization rate for input gas i for process sub-type or process type j (expressed as a decimal fraction).

a$_{ij}$ = Fraction of input gas i used in process sub-type or process type j with abatement systems, on a fab basis (expressed as a decimal fraction).

d$_{ij}$ = Fraction of input gas i destroyed or removed in abatement systems connected to process tools where process sub-type, or process type j is used, on a fab basis (expressed as a decimal fraction). This is zero unless the facility adheres to the requirements in § 98.94(f).

UT$_{ij}$ = The average uptime factor of all abatement systems connected to process tools in the fab using input gas i in process sub-type or process type j, as calculated in Equation I–15 of this subpart, on a fab basis (expressed as a decimal fraction).

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

j = Process sub-type or process type.

~~$BE_{ijk} = B_{ijk} * C_{ij} * (1 - a_{ij} * d_{jk}) * 0.001$~~

$$BE_{ijk} = B_{ijk} * C_{ij} * \left(1 - \left(a_{ij} * d_{jk} * UT_{ijk}\right)\right) * 0.001 \tag{Eq. I-9}$$

Where:

BE_{ijk} = Annual emissions of by-product gas k formed from input gas i from process sub-type or process type j, on a fab basis (metric tons).

B_{ijk} = By-product formation rate of gas k created as a by-product per amount of input gas i (kg) consumed by process sub-type or process type j (kg).

C_{ij} = Amount of input gas i consumed for process sub-type, or process type j, as calculated in Equation I–13 of this subpart, on a fab basis (kg).

a_{ij} = Fraction of input gas i used for process sub-type, or process type j with abatement systems, on a fab basis (expressed as a decimal fraction).

d_{jk} = Fraction of by-product gas k destroyed or removed in abatement systems connected to process tools where process sub-type, or process type j is used, on a fab basis (expressed as a decimal fraction). This is zero unless the facility adheres to the requirements in §98.94(f).

UT_{ijk} = The average uptime factor of all abatement systems connected to process tools in the fab emitting by-product gas k, formed from input gas i in process sub-type or process type j, on a fab basis (expressed as a decimal fraction). For this equation, UT_{ijk} is assumed to be equal to UT_{ij} as calculated in Equation I–15 of this subpart.

0.001 = Conversion factor from kg to metric tons.

i = Input gas.

j = Process sub-type or process type.

k = By-product gas.

(ii) You must calculate annual fab-level emissions of each fluorinated GHG used for each of the process sub-types associated with the chamber cleaning process type, including in-situ plasma chamber clean, remote plasma chamber clean, and in-situ thermal chamber clean, using default utilization and by-product formation rates as shown in Table I–3 or I–4 of this subpart, and by using Equations I–8 and I–9 of this subpart.

(iii) If default values are not available for a particular input gas and process type or sub-type combination in Tables I–3 or I–4, you must follow the procedures in paragraph (a)(6) of this section.

(2) If you manufacture MEMS, LCDs, or PVs, you must calculate annual fab-level emissions of each fluorinated GHG used for the plasma etching and chamber cleaning process types using default utilization and by-product formation rates as shown in Table I–5, I–6, or I–7 of this subpart, as appropriate, and by using Equations I–8 and I–9 of this subpart. If default values are not available for a particular input gas and process type or sub-type combination in Tables I–5, I–6, or I–7, you must follow the procedures in paragraph (a)(6) of this section. If your fab uses less than 50 kg of a fluorinated GHG in one reporting year, you may calculate emissions as equal to your fab's annual consumption for that specific gas as calculated in Equation I–11 of this subpart, plus any by-product emissions of that gas calculated under this paragraph (a).

(3)–(5) [Reserved]

(6) If you are required, or elect, to perform calculations using default emission factors for gas utilization and by-product formation rates according to the procedures in paragraphs (a)(1) or (a)(2) of this section, and default values are not available for a particular input gas and process type or sub-type combination in Tables I–3, I–4, I–5, I–6, or I–7, you must use the utilization and by-product formation rates of zero and use Equations I–8 and I–9 of this subpart.

(b) You must calculate annual fab-level N_2O emissions from all chemical vapor deposition processes and from the aggregate of all other electronics manufacturing production processes using Equation I–10 of this subpart and the methods in paragraphs (b)(1) and (2) of this section. If your fab uses less than 50 kg of N_2O in one reporting year, you may calculate fab emissions as equal to your fab's annual consumption for N_2O as calculated in Equation I–11 of this subpart.

$$E(N_2O)_j = C_{N_2O,j} * \left(1 - U_{N_2O,j}\right) * \left(1 - \left(a_{N_2O,j} * d_{N_2O,j} * UT_{N2O}\right)\right) * 0.001 \qquad \text{(Eq. I-10)}$$

Where:

$E(N_2O)_j$ = Annual emissions of N_2O for N_2O-using process j, on a fab basis (metric tons).

$C_{N2O,j}$ = Amount of N_2O consumed for N_2O-using process j, as calculated in Equation I–13 of this subpart and apportioned to N_2O process j, on a fab basis (kg).

$U_{N2O,j}$ = Process utilization factor for N_2O-using process j (expressed as a decimal fraction) from Table I–8 of this subpart.

$a_{N2O,j}$ = Fraction of N_2O used in N_2O-using process j with abatement systems, on a fab basis (expressed as a decimal fraction).

$d_{N2O,j}$ = Fraction of N_2O for N_2O-using process j destroyed or removed in abatement systems connected to process tools where process j is used, on a fab basis (expressed as a decimal fraction). This is zero unless the facility adheres to the requirements in § 98.94(f).

UT_{N2O} = The average uptime factor of all the abatement systems connected to process tools in the fab that use N_2O, as calculated in Equation I–15 of this subpart, on a fab basis (expressed as a decimal fraction). For purposes of calculating the abatement system uptime for N_2O using process tools, in Equation I–15 of this subpart, the only input gas i is N_2O, j is the N_2O using process, and p is the N_2O abatement system connected to the N_2O using tool.

0.001 = Conversion factor from kg to metric tons.

j = Type of N_2O-using process, either chemical vapor deposition or all other N_2O-using manufacturing processes.

(1) You must use the factor for N_2O utilization for chemical vapor deposition processes as shown in Table I–8 to this subpart.

(2) You must use the factor for N_2O utilization for all other manufacturing production processes other than chemical vapor deposition as shown in Table I–8 to this subpart.

(c) You must calculate total annual input gas i consumption on a fab basis for each fluorinated GHG and N_2O using Equation I–11 of this subpart. Where a gas supply system serves more than one fab, Equation I–11 is applied to that gas which has been apportioned to each fab served by that system using the apportioning factors determined in accordance with § 98.94(c).

$$C_i = (I_{Bi} - I_{Ei} + A_i - D_i) \qquad \text{(Eq. I-11)}$$

where:

C_i = Annual consumption of input gas i, on a fab basis (kg per year).

I_{Bi} = Inventory of input gas i stored in containers at the beginning of the reporting year, including heels, on a fab basis (kg). For containers in service at the beginning of a reporting year, account for the quantity in these containers as if they were full.

I_{Ei} = Inventory of input gas i stored in containers at the end of the reporting year, including heels, on a fab basis (kg). For containers in service at the end of a reporting year, account for the quantity in these containers as if they were full.

A_i = Acquisitions of input gas i during the year through purchases or other transactions, including heels in containers returned to the electronics manufacturing facility, on a fab basis (kg).

D_i = Disbursements of input gas i through sales or other transactions during the year, including heels in containers returned by the electronics manufacturing facility to the chemical supplier, as calculated using Equation I–12 of this subpart, on a fab basis (kg).

i = Input gas.

(d) You must calculate disbursements of input gas i using fab-wide gas-specific heel factors, as determined in § 98.94(b), and by using Equation I–12 of this subpart. Where a gas supply system serves more than one fab, Equation I–12 is applied to that gas which has been apportioned to each fab served by that system using the apportioning factors determined in accordance with § 98.94(c).

$$D_i = \sum_{l=1}^{M} \left(h_{il} * N_{il} * F_{il} \right) + X_i \quad \text{(Eq. I-12)}$$

where:

D_i = Disbursements of input gas i through sales or other transactions during the reporting year on a fab basis, including heels in containers returned by the electronics manufacturing fab to the gas distributor (kg).

h_{il} = Fab-wide gas-specific heel factor for input gas i and container size and type l (expressed as a decimal fraction), as determined in § 98.94(b). If your fab uses less than 50 kg of a fluorinated GHG or N_2O in one reporting year, you may assume that any h_{il} for that fluorinated GHG or N_2O is equal to zero.

N_{il} = Number of containers of size and type l returned to the gas distributor containing the standard heel of input gas i.

F_{il} = Full capacity of containers of size and type l containing input gas i, on a fab basis (kg).

X_i = Disbursements under exceptional circumstances of input gas i through sales or other transactions during the year, on a fab basis (kg). These include returns of containers whose contents have been weighed due to an exceptional circumstance as specified in § 98.94(b)(4).

i = Input gas.

l = Size and type of gas container.

M = The total number of different sized container types on a fab basis. If only one size and container type is used for an input gas i, M=1

(e) You must calculate the amount of input gas i consumed, on a fab basis, for each process sub-type or process type j, using Equation I–13 of this subpart. Where a gas supply system serves more than one fab, Equation I–13 is applied to that gas which has been apportioned to each fab served by that system using the apportioning factors determined in accordance with § 98.94(c). If you elect to calculate emissions using the stack test method in paragraph (i) of this section, you must calculate the amount of input gas i consumed on the applicable basis by using an appropriate apportioning factor. For example, when calculating fab-level emissions of each fluorinated GHG consumed using Equation I–21 of this section, you must substitute the term fij with the appropriate apportioning factor to calculate the total consumption of each fluorinated GHG in tools that are vented to stack systems that are tested.

$$C_{ij} = f_{ij} * C_i \quad \text{(Eq. I-13)}$$

where:

$C_{i,j}$ = The annual amount of input gas i consumed, on a fab basis, for process sub-type or process type j (kg).

$f_{i,j}$ = Process sub-type-specific or process type-specific j, input gas i apportioning factor (expressed as a decimal fraction), as determined in accordance with § 98.94(c).

C_i = Annual consumption of input gas i, on a fab basis, as calculated using Equation I–11 of this subpart (kg).

i = Input gas.

j = Process sub-type or process type.

(f) [Reserved]

(g) If you report controlled emissions pursuant to § 98.94(f), you must calculate the uptime of all the abatement systems for each combination of input gas or by-product gas, and process sub-type or process type, by using Equation I–15 of this subpart.

$$UT_{ij} = 1 - \frac{\sum_p Td_{ijp}}{\sum_p UT_{ijp}} \qquad \text{(Eq. I-15)}$$

Where:

UT_{ij} = The average uptime factor of all abatement systems connected to process tools in the fab using input gas i in process sub-type or process type j (expressed as a decimal fraction).

Td_{ijp} = The total time, in minutes, that abatement system p, connected to process tool(s) in the fab using input gas i in process sub-type or process type j, is not in operational mode, as defined in § 98.98, when at least one of the tools connected to abatement system p is in operation.

UT_{ijp} = Total time, in minutes per year, in which abatement system p has at least one associated tool in operation. For determining the amount of tool operating time, you may assume that tools that were installed for the whole of the year were operated for 525,600 minutes per year. For tools that were installed or uninstalled during the year, you must prorate the operating time to account for the days in which the tool was not installed; treat any partial day that a tool was installed as a full day (1,440 minutes) of tool operation. For an abatement system that has more than one connected tool, the tool operating time is 525,600 minutes per year if at least one tool was installed at all times throughout the year. If you have tools that are idle with no gas flow through the tool for part of the year, you may calculate total tool time using the actual time that gas is flowing through the tool.

i = Input gas.

j = Process sub-type or process type.

p = Abatement system.

(h) If you use fluorinated heat transfer fluids, you must calculate the annual emissions of fluorinated heat transfer fluids on a fab basis using the mass balance approach described in Equation I–16 of this subpart.

$$EH_i = density_i * (I_{iB} + P_i - N_i + R_i - I_{iE} - D_i) * 0.001 \qquad \text{(Eq. I-16)}$$

where:

EH_i = Emissions of fluorinated heat transfer fluid i, on a fab basis (metric tons/year).

$Density_i$ = Density of fluorinated heat transfer fluid i (kg/l).

I_{iB} = Inventory of fluorinated heat transfer fluid i, on a fab basis, in containers other than equipment at the beginning of the reporting year (in stock or storage) (l). The inventory at the beginning of the reporting year must be the same as the inventory at the end of the previous reporting year.

P_i = Acquisitions of fluorinated heat transfer fluid i, on a fab basis, during the reporting year (l), including amounts purchased from chemical suppliers, amounts purchased from equipment suppliers with or inside of equipment, and amounts returned to the facility after off-site recycling.

N_i = Total nameplate capacity (full and proper charge) of equipment that uses fluorinated heat transfer fluid i and that is newly installed in the fab during the reporting year (l).

R_i = Total nameplate capacity (full and proper charge) of equipment that uses fluorinated heat transfer fluid i and that is removed from service in the fab during the reporting year (l).

I_{iE} = Inventory of fluorinated heat transfer fluid i, on a fab basis, in containers other than equipment at the end of the reporting year (in stock or storage) (l). The inventory at the beginning of the reporting year must be the same as the inventory at the end of the previous reporting year.

D_i = Disbursements of fluorinated heat transfer fluid i, on a fab basis, during the reporting year, including amounts returned to chemical suppliers, sold with or inside of equipment, and sent off-site for verifiable recycling or destruction (l). Disbursements should include only amounts that are properly stored and transported so as to prevent emissions in transit.

0.001 = Conversion factor from kg to metric tons.

i = Fluorinated heat transfer fluid.

(1) If you use a fluorinated chemical both as a fluorinated heat transfer fluid and in other applications, you may calculate and report either emissions from all applications or from

only those specified in the definition of *fluorinated heat transfer fluids in § 98.98.*

(2) [Reserved]

(i) *Stack Test Method.* As an alternative to the default emission factor method in paragraph (a) of this section, you may calculate fab-level fluorinated GHG emissions using fab-specific emission factors developed from stack testing. To use the method in this paragraph, you must first make a preliminary estimate of the fluorinated GHG emissions from each stack system in the fab under paragraph (i)(1) of this section. You must then compare the preliminary estimate for each stack system to the criteria in paragraph (i)(2) of this section to determine whether the stack system meets the criteria for using the stack test method described in paragraph (i)(3) of this section or whether the stack system meets the criteria for using the method described in paragraph (i)(4) of this section to estimate emissions from the stack systems that are not tested.

(1) *Preliminary estimate of emissions by stack system in the fab.* You must calculate a preliminary estimate of the total annual emissions, on a metric ton CO_2e basis, of all fluorinated GHG from each stack system in the fab using default utilization and by-product formation rates as shown in Table I–11, I–12, I–13, I–14, or I–15 of this subpart, as applicable, and by using Equations I–8 and I–9 of this subpart. You must include any intermittent low-use fluorinated GHGs, as defined in § 98.98 of this subpart, in any preliminary estimates. When using Equations I–8 and I–9 of this subpart for the purposes of this paragraph (i)(1), you must also adhere to the procedures in paragraphs (i)(1)(i) to (iv) of this section to calculate preliminary estimates.

(i) When you are calculating preliminary estimates for the purpose of this paragraph (i)(1), you must consider the subscript ''j'' in Equations I–8 and I–9, and I–13 of this subpart to mean ''stack system'' instead of ''process sub-type or process type.'' For the value of a_{ij}, the fraction of input gas i that is used in tools with abatement systems, for use in Equations I–8 and I–9, you may use the ratio of the number of tools using input gas i that have abatement systems that are vented to the stack system for which you are calculating the preliminary estimate to the total number of tools using input gas i that are vented to that stack system, expressed as a decimal fraction. In calculating the preliminary estimates, you must account for the effect of any fluorinated GHG abatement system meeting the definition of abatement system in § 98.98. You may use this approach to determining a_{ij} only for this preliminary estimate.

(ii) You must use representative data from the previous reporting year to estimate the consumption of input gas i as calculated in Equation I–13 of this subpart and the fraction of input gas i destroyed in abatement systems for each stack system as calculated by Equation I–24 of this subpart. If you were not required to submit an annual report under subpart I for the previous reporting year and data from the previous reporting year are not available, you may estimate the consumption of input gas i and the fraction of input gas i destroyed in abatement systems based on representative operating data from a period of at least 30 days in the current reporting year. When calculating the consumption of input gas i using Equation I–13 of this subpart, the term ''f_{ij}'' is replaced with the ratio of the number of tools using input gas i that are vented to the stack system for which you are calculating the preliminary estimate to the total number of tools in the fab using input gas i, expressed as a decimal fraction. You may use this approach to determining f_{ij} only for this preliminary estimate.

(iii) You must use representative data from the previous reporting year to estimate the total uptime of all abatement systems for the stack system as calculated by Equation I–23 of this subpart, instead of using Equation I–15 of this subpart to calculate the average uptime factor. If you were not required to submit an annual report under subpart I for the previous reporting year and data from the previous reporting year are not available, you may estimate the total uptime of all abatement systems for the stack system based on representative operating data from a period of at least 30 days in the current reporting year.

(iv) If you anticipate an increase or decrease in annual consumption or emissions of any fluorinated GHG, or the number of tools connected to abatement systems greater than 10 percent for the current reporting year compared to the previous reporting year, you must account for the anticipated change in your preliminary estimate. You may account for such a change using a quantifiable metric (e.g., the ratio of the number tools that are expected to be vented to the stack system in the current year as compared to the previous reporting year, ratio of the expected number of wafer starts in the current reporting year as compared to the previous reporting year), engineering judgment, or other industry standard practice.

(2) *Method selection for stack systems in the fab.* If the calculations under paragraph (i)(1) of this section, as well as any subsequent annual measurements and calculations under this subpart, indicate that the stack system meets the criteria in paragraph (i)(2)(i) through (iii) of this section, then you may comply with either paragraph (i)(3) of this section (stack test method) or paragraph (i)(4) of this section (method to estimate emissions from the stack systems that are not tested). If the stack system does not meet all three criteria in paragraph (i)(2)(i) through (iii) of this section, then you must comply with the stack test method specified in paragraph (i)(3) of this section. For those fluorinated GHGs in Tables I–11, I–12, I–13, I–14, and I–15 of this subpart for which Table A–1 to subpart A of this part does not define a GWP value, you must use a value of 2,000 for the GWP in calculating metric ton CO_2e for that fluorinated GHG for use in paragraphs (i)(2)(i) through (iii) of this section.

(i) The sum of annual emissions of fluorinated GHGs from all of the combined stack systems that are not tested in the fab must be less than 10,000 metric ton CO_2e per year.

(ii) When all stack systems in the fab are ordered from lowest to highest emitting in metric ton CO_2e of fluorinated GHG per year, each of the stack systems that is not tested must be within the set of the fab's lowest emitting fluorinated GHG stack systems that together emit 15 percent or less of total CO_2e fluorinated GHG emissions from the fab.

(iii) Fluorinated GHG emissions from each of the stack systems that is not tested can only be attributed to particular process tools during the test (that is, the stack system that is not tested cannot be used as an alternative emission point or bypass stack system from other process tools not attributed to the untested stack system).

(3) *Stack system stack test method.* For each stack system in the fab for which testing is required, measure the emissions of each fluorinated GHG from the stack system by conducting an emission test. In addition, measure the fab-specific consumption of each fluorinated GHG by the tools that are vented to the stack systems tested. Measure emissions and consumption of each fluorinated GHG as specified in § 98.94(j). Develop fab-specific emission factors and calculate fab-level fluorinated GHG emissions using the procedures specified in paragraph (i)(3)(i) through (viii) of this section. All emissions test data and procedures used in developing emission factors must be documented and recorded according to § 98.97.

(i) You must measure, and, if applicable, apportion the fab-specific fluorinated GHG consumption of the tools that are vented to the stack systems that are tested during the emission test as specified in § 98.94(j)(3). Calculate the consumption for each fluorinated GHG for the test period.

(ii) You must calculate the emissions of each fluorinated GHG consumed as an input gas using Equation I–17 of this subpart and each fluorinated GHG formed as a by-product gas using Equation I–18 of this subpart and the procedures specified in paragraphs (i)(3)(ii)(A) through (E) of this section. If a stack system is comprised of multiple stacks, you must sum the emissions from each stack in the stack system when using Equation I–17 or Equation I–18 of this subpart.

$$E_{is} = MW_i * Q_j * \frac{1}{SV} * \frac{1}{10^3} * \sum_{s=1}^{N} \frac{X_{ism}}{10^9} * \Delta t_m \qquad \text{(Eq. I-17)}$$

Where:

E_{is} = Total fluorinated GHG input gas i, emitted from stack system s, during the sampling period (kg).

X_{ism} = Average concentration of fluorinated GHG input gas i in stack system s, during the time interval m (ppbv).

MW_i = Molecular weight of fluorinated GHG input gas i (g/g-mole).

Q_s = Flow rate of the stack system s, during the sampling period (m^3/min).

SV = Standard molar volume of gas (0.0240 m^3/g-mole at 68 °F and 1 atm).

Δt_m = Length of time interval m (minutes). Each time interval in the FTIR sampling period must be less than or equal to 60 minutes (for example an 8 hour sampling period would consist of at least 8 time intervals).

$1/10^3$ = Conversion factor (1 kilogram/1,000 grams).

i = Fluorinated GHG input gas.

s = Stack system.

N = Total number of time intervals m in sampling period.

m = Time interval.

$$E_{ks} = MW_k * Q_s * \frac{1}{SV} * \frac{1}{10^3} * \sum_{m=1}^{N} \frac{X_{ksm}}{10^9} * \Delta t_m \qquad \text{(Eq. I-18)}$$

Where:

E_{ks} = Total fluorinated GHG by-product gas k, emitted from stack system s, during the sampling period (kg).

X_{ks} = Average concentration of fluorinated GHG by-product gas k in stack system s, during the time interval m (ppbv).

MW_k = Molecular weight of the fluorinated GHG by-product gas k (g/g-mole).

Q_s = Flow rate of the stack system s, during the sampling period (m^3/min).

SV = Standard molar volume of gas (0.0240 m^3/g-mole at 68 °F and 1 atm).

Δt_m = Length of time interval m (minutes). Each time interval in the FTIR sampling period must be less than or equal to 60 minutes (for example an 8 hour sampling period would consist of at least 8 time intervals).

$1/10^3$ = Conversion factor (1 kilogram/1,000 grams).

k = Fluorinated GHG by-product gas.

s = Stack system.

N = Total number of time intervals m in sampling period.

m = Time interval.

(A) If a fluorinated GHG is consumed during the sampling period, but emissions are not detected, use one-half of the field detection limit you determined for that fluorinated GHG according to § 98.94(j)(2) for the value of ''X_{ism}'' in Equation I–17.

(B) If a fluorinated GHG is consumed during the sampling period and detected intermittently during the sampling period, use the detected concentration for the value of ''X_{ism}'' in Equation I–17 when available and use one-half of the field detection limit you determined for that fluorinated GHG according to § 98.94(j)(2) for the value of ''X_{ism}'' when the fluorinated GHG is not detected.

(C) If an expected or possible by-product, as listed in Table I–17 of this subpart, is detected intermittently during the sampling period, use the measured concentration for ''X_{ksm}'' in Equation I–18 when available and use one-half of the field detection limit you determined for that fluorinated GHG according to § 98.94(j)(2) for the value of ''X_{ksm}'' when the fluorinated GHG is not detected.

(D) If a fluorinated GHG is not consumed during the sampling period and is an expected by-product gas as listed in Table I–17 of this subpart and is not detected during the sampling period, use one-half of the field detection limit you determined for that fluorinated GHG according to § 98.94(j)(2) for the value of ''X_{ksm}'' in Equation I–18.

(E) If a fluorinated GHG is not consumed during the sampling period and is a possible by-product gas as listed in Table I–17 of this subpart, and is not detected during the sampling period, then assume zero emissions for that fluorinated GHG for the tested stack system.

(iii) You must calculate a fab-specific emission factor for each fluorinated GHG input gas consumed (in kg of fluorinated GHG emitted per kg of input gas i consumed) in the tools that vent to stack systems that are tested, as applicable, using Equation I–19 of this subpart. If the emissions of input gas i exceed the consumption of input gas i during the sampling period, then equate "E_{is}" to the consumption of input gas i and treat the difference between the emissions and consumption of input gas i as a by-product of the other input gases, using Equation I–20 of this subpart.

$$EF_{if} = \frac{\sum_{s}\left(E_{is}\right)}{Activity_{if} * \left(UT_f + \left(\frac{1-UT_f}{1-(a_{if} * d_{if})}\right)\right)} \qquad \text{(Eq. I-19)}$$

Where:

EF_{if} = Emission factor for fluorinated GHG input gas i, from fab f, representing 100 percent abatement system uptime (kg emitted/kg input gas consumed).

E_{is} = Mass emission of fluorinated GHG input gas i from stack system s, during the sampling period (kg emitted).

$Activity_{if}$ = Consumption of fluorinated GHG input gas i, for fab f, in the tools vented to the stack systems being tested, during the sampling period, as determined following the procedures specified in § 98.94(j)(3) (kg consumed).

UT_f = The total uptime of all abatement systems for fab f, during the sampling period, as calculated in Equation I–23 of this subpart (expressed as decimal fraction). If the stack system does not have abatement systems on the tools vented to the stack system, the value of this parameter is zero.

a_{if} = Fraction of fluorinated GHG input gas i used in fab f in tools with abatement systems (expressed as a decimal fraction).

d_{if} = Fraction of fluorinated GHG input gas i destroyed or removed in abatement systems connected to process tools in fab f, as calculated in Equation I–24 of this subpart (expressed as decimal fraction). If the stack system does not have abatement systems on the tools vented to the stack system, the value of this parameter is zero.

f = Fab.

i = Fluorinated GHG input gas.

s = Stack system.

(iv) You must calculate a fab-specific emission factor for each fluorinated GHG formed as a by-product (in kg of fluorinated GHG per kg of total fluorinated GHG consumed) in the tools vented to stack systems that are tested, as applicable, using Equation I–20 of this subpart. When calculating the by-product emission factor for an input gas for which emissions exceeded its consumption, exclude the consumption of that input gas from the term "$\boldsymbol{\Sigma}(Activity_{if})$."

$$EF_{kf} = \frac{\sum_{s}\left(E_{ks}\right)}{\sum_{i}\left(Activity_{if}\right) * \left(UT_f + \left(\frac{1-UT_f}{1-(a_f * d_{kf})}\right)\right)} \qquad \text{(Eq. I-20)}$$

Where:

EF_{kf} = Emission factor for fluorinated GHG by-product gas k, from fab f, representing 100 percent abatement system uptime (kg emitted/kg of all input gases consumed in tools vented to stack systems that are tested).

E_{ks} = Mass emission of fluorinated GHG by-product gas k, emitted from stack system s, during the sampling period (kg emitted).

$Activity_{if}$ = Consumption of fluorinated GHG input gas i for fab f in tools vented to stack systems that are tested, during the sampling period as determined following the procedures specified in § 98.94(j)(3) (kg consumed).

UT_f = The total uptime of all abatement systems for fab f, during the sampling period, as calculated in Equation I–23 of this subpart (expressed as decimal fraction).

a_f = Fraction of all fluorinated input gases used in fab f in tools with abatement systems (expressed as a decimal fraction).

d_{kf} = Fraction of fluorinated GHG by-product gas k destroyed or removed in abatement systems connected to process tools in fab f, as calculated in Equation I–24 of this subpart (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

k = Fluorinated GHG by-product gas.

s = Stack system.

(v) You must calculate annual fab-level emissions of each fluorinated GHG consumed using Equation I–21 of this section.

$$E_{if} = EF_{if} * C_{if} * UT_f + \frac{EF_{if}}{\left(1 - (a_{if} * d_{if})\right)} * C_{if} * \left(1 - UT_f\right) \qquad \text{(Eq. I-21)}$$

Where:

E_{if} = Annual emissions of fluorinated GHG input gas i (kg/year) from the stack systems that are tested for fab f.

EF_{if} = Emission factor for fluorinated GHG input gas i emitted from fab f, as calculated in Equation I–19 of this subpart (kg emitted/kg input gas consumed).

C_{if} = Total consumption of fluorinated GHG input gas i in tools that are vented to stack systems that are tested, for fab f, for the reporting year, as calculated using Equation I–13 of this subpart (kg/year).

UT_f = The total uptime of all abatement systems for fab f, during the reporting year, as calculated using Equation I–23 of this subpart (expressed as a decimal fraction).

a_{if} = Fraction of fluorinated GHG input gas i used in fab f in tools with abatement systems (expressed as a decimal fraction).

d_{if} = Fraction of fluorinated GHG input gas i destroyed or removed in abatement systems connected to process tools in fab f that are included in the stack testing option, as calculated in Equation I–24 of this subpart (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

(vi) You must calculate annual fab-level emissions of each fluorinated GHG by-product formed using Equation I–22 of this section.

$$E_{kf} = EF_{kf} * \sum_i C_{if} * UT_f + \frac{EF_{kf}}{\left(1 - (a_f * d_{kf})\right)} * \sum_i C_{if} * \left(1 - UT_f\right) \qquad \text{(Eq. I-22)}$$

Where:

Ek_f = Annual emissions of fluorinated GHG by-product k (kg/year) from the stack systems that are tested for fab f.

EF_{kf} = Emission factor for fluorinated GHG by-product k, emitted from fab f, as calculated in Equation I–20 of this subpart (kg emitted/kg of all fluorinated input gases consumed).

C_{if} = Total consumption of fluorinated GHG input gas i in tools that are vented to stack systems that are tested, for fab f, for the reporting year, as calculated using Equation I–13 of this subpart.

UT_f = The total uptime of all abatement systems for fab f, during the reporting year as calculated using Equation I–23 of this subpart (expressed as a decimal fraction).

a_f = Fraction of fluorinated input gases used in fab f in tools with abatement systems (expressed as a decimal fraction).

dk_f = Fraction of fluorinated GHG by-product k destroyed or removed in abatement systems connected to process tools in fab f that are included in the stack testing option, as calculated in Equation I–24 of this subpart (expressed as decimal fraction).

f = Fab.

i = Fluorinated GHG input gas.

k = Fluorinated GHG by-product

(vii) When using the stack testing method described in this paragraph (i), you must calculate abatement system uptime on a fab basis using Equation I–23 of this subpart. When calculating abatement system uptime for use in Equation I–19 and I–20 of this subpart, you must evaluate the variables "Td_{pf}" and "UT_{pf}" for the sampling period instead of the reporting year.

$$UT_f = 1 - \frac{\sum_p Td_{pf}}{\sum_p UT_{pf}} \qquad \text{(Eq. I-23)}$$

Where:

UT_f = The average uptime factor for all abatement systems in fab f (expressed as a decimal fraction).

Td_{pf} = The total time, in minutes, that abatement system p, connected to process tool(s) in fab f, is not in operational mode as defined in § 98.98.

UT_{pf} = Total time, in minutes per year, in which the tool(s) connected at any point during the year to abatement system p, in fab f could be in operation. For determining the amount of tool operating time, you may assume that tools that were installed for the whole of the year were operated for 525,600 minutes per year. For tools that were installed or uninstalled during the year, you must prorate the operating time to account for the days in which the tool was not installed; treat any partial day that a tool was installed as a full day (1,440 minutes) of tool operation. For an abatement system that has more than one connected tool, the tool operating time is 525,600 minutes per year if there was at least one tool installed at all times throughout the year. If you have tools that are idle with no gas flow through the tool, you may calculate total tool time using the actual time that gas is flowing through the tool.

f = Fab.

p = Abatement system.

(viii) When using the stack testing option described in this paragraph (i), you must calculate the weighted-average fraction of fluorinated input gas i destroyed or removed in abatement systems for each fab f, as applicable, byusing Equation I–24 of this subpart.

$$d_{if} = \frac{\sum_j C_{ijf} * DRE_{ij}}{\sum_j C_{ijf}} \qquad \text{(Eq. I-24)}$$

Where:

d_{if} = The average weighted fraction of fluorinated GHG input gas i destroyed or removed in abatement systems in fab f (expressed as a decimal fraction).

C_{ijf} = The amount of fluorinated GHG input gas i consumed for process type j fed into abatement systems in fab f as calculated using Equation I–13 of this subpart (kg).

DRE_{ij} = Destruction or removal efficiency for fluorinated GHG input gas i in abatement systems connected to process tools where process type j is used (expressed as a decimal fraction) determined according to § 98.94(f).

f = fab.

i = Fluorinated GHG input gas.

j = Process type.

(4) *Method to calculate emissions from stack systems that are not tested.* You must calculate annual fab-level emissions of each fluorinated GHG input gas and by-product gas for those fluorinated GHG listed in paragraphs (i)(4)(i) and (ii) of this section using default utilization and by-product formation rates as shown in Tables I–11, I–12, I–13, I–14, or I–15 of this subpart, as applicable, and by using Equations I–8, I–9, and I–13 of this subpart. When using Equations I–8, I–9, and I–13 of this subpart to fulfill the requirements of this paragraph, you must use, in place of the term C_{ij} in each equation, the total consumption of each fluorinated GHG meeting the criteria in paragraph (i)(4)(i) of this section or that is used in tools vented to the stack systems that meet the criteria in paragraph (i)(4)(ii) of this section. You must use, in place of the term a_{ij}, the fraction of fluorinated GHG meeting the criteria in paragraph (i)(4)(i) of this section used in tools with abatement systems or that is used in tools with abatement systems that are vented to the stack

systems that meet the criteria in paragraph (i)(4)(ii) of this section. You also must use the results of Equation I–24 of this subpart in place of the terms d_{ij} in Equation I–8 of this subpart and d_{jk} in Equation I–9 of this subpart, and use the results of Equation I–23 of this subpart in place of the results of Equation I–15 of this subpart for the term UT_{ij}.

(i) Calculate emissions from consumption of each intermittent low-use fluorinated GHG as defined in §98.98 of this subpart using the default utilization and by-product formation rates and equations specified in paragraph (i)(4) of this section. If a fluorinated GHG was not being used during the stack testing and does not meet the definition of intermittent low-use fluorinated GHG in §98.98, then you must test the stack systems associated with the use of that fluorinated GHG at a time when that gas is in use at a magnitude that would allow you to determine an emission factor for that gas according to the procedures specified in paragraph (i)(3) of this section.

(ii) Calculate emissions from consumption of each fluorinated GHG used in tools vented to stack systems that meet the criteria specified in paragraphs (i)(2)(i) through (i)(2)(iii) of this section, and were not tested according to the procedures in paragraph (i)(3) of this section. Calculate emissions using the default utilization and by-product formation rates and equations specified in paragraph (i)(4) of this section. If you are using a fluorinated GHG not listed in Tables I–11, I–12, I–13, I–14, or I–15 of this subpart, then you must assume utilization and by-product formation rates of zero for that fluorinated GHG.

(5) To determine the total emissions of each fluorinated GHG from each fab under this stack testing option, you must sum the emissions of each fluorinated GHG determined from the procedures in paragraph (i)(3) of this section with the emissions of the same fluorinated GHG determined from the procedures in paragraph (i)(4) of this section. Sum the total emissions of each fluorinated GHG from all fabs at your facility to determine the facility-level emissions of each fluorinated GHG.

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§98.94 Monitoring and QA/QC requirements.

(a) [Reserved]

(b) For purposes of Equation I–12 of this subpart, you must estimate fab-wide gas-specific heel factors for each container type for each gas used, according to the procedures in paragraphs (b)(1) through (b)(5) of this section. This paragraph (b) does not apply to fluorinated GHGs or N_2O that your fab uses in quantities of less than 50 kg in one reporting year and for which you calculate emissions as equal to consumption under §98.93(a)(1), (a)(2), or (b), or for any intermittent low-use fluorinated GHG for which you calculate emissions according to §98.93(i)(4)(i).

(1) Base your fab-wide gas-specific heel factors on the trigger point for change out of a container for each container size and type for each gas used. Fab-wide gas-specific heel factors must be expressed as the ratio of the trigger point for change out, in terms of mass, to the initial mass in the container, as determined by paragraphs (b)(2) and (3) of this section.

(2) The trigger points for change out you use to calculate fab-wide gas-specific heel factors in paragraph (b)(1) of this section must be determined by monitoring the mass or the pressure of your containers. If you monitor the pressure, convert the pressure to mass using the ideal gas law, as displayed in Equation I–25 of this subpart, with the appropriate Z value selected based upon the properties of the gas.

$$pV = ZnRT \qquad \text{(Eq. I-25)}$$

Where:

p = Absolute pressure of the gas (Pa).

V = Volume of the gas container (m^3).

Z = Compressibility factor.

n = Amount of substance of the gas (moles).
R = Gas constant (8.314 Joule/Kelvin mole).
T = Absolute temperature (K).

(3) The initial mass you use to calculate a fab-wide gas-specific heel factor in paragraph (b)(1) of this section may be based on the weight of the gas provided to you in gas supplier documents; however, you remain responsible for the accuracy of these masses and weights under this subpart.

(4) If a container is changed in an exceptional circumstance, as specified in paragraphs (b)(4)(i) and (ii) of this section, you must weigh that container or measure the pressure of that container with a pressure gauge, in place of using a heel factor to determine the residual weight of gas. When using mass-based trigger points for change out, you must determine if an exceptional circumstance has occurred based on the net weight of gas in the container, excluding the tare weight of the container.

(i) For containers with a maximum storage capacity of less than 9.08 kg (20 lbs) of gas, an exceptional circumstance is a change out point that differs by more than 50 percent from the trigger point for change out used to calculate your fab-wide gas-specific heel factor for that gas and container type.

(ii) For all other containers, an exceptional circumstance is a change out point that differs by more than 20 percent from the trigger point for change out used to calculate your fab-wide gas-specific heel factor for that gas and container type.

(5) You must re-calculate a fab-wide gas-specific heel factor if you execute a process change to modify the trigger point for change out for a gas and container type that differs by more than 5 percent from the previously used trigger point for change out for that gas and container type.

(c) You must develop apportioning factors for fluorinated GHG and N_2O consumption (including the fraction of gas consumed by process tools connected to abatement systems as in Equations I–8, I–9, I–10, I–19, I–20, I–21, and I–22 of this subpart), to use in the equations of this subpart for each input gas i, process sub-type, process type, stack system, and fab as appropriate, using a fab-specific engineering model that is documented in your site GHG Monitoring Plan as required under § 98.3(g)(5). This model must be based on a quantifiable metric, such as wafer passes or wafer starts, or direct measurement of input gas consumption as specified in paragraph (c)(3) of this section. To verify your model, you must demonstrate its precision and accuracy by adhering to the requirements in paragraphs (c)(1) and (2) of this section.

(1) You must demonstrate that the fluorinated GHG and N_2O apportioning factors are developed using calculations that are repeatable, as defined in § 98.98.

(2) You must demonstrate the accuracy of your fab-specific model by comparing the actual amount of input gas i consumed and the modeled amount of input gas i consumed in the fab, as follows:

(i) You must analyze actual and modeled gas consumption for a period when the fab is at a representative operating level (as defined in § 98.98) lasting at least 30 days but no more than the reporting year.

(ii) You must compare the actual gas consumed to the modeled gas consumed for one fluorinated GHG reported under this subpart for the fab. You must certify that the fluorinated GHG selected for comparison corresponds to the largest quantity, on a mass basis, of fluorinated GHG consumed at the fab during the reporting year for which you are required to apportion following the procedures specified in § 98.93(a), (b), or (i). You may compare the actual gas consumed to the modeled gas consumed for two fluorinated GHGs and demonstrate conformance according to paragraph (c)(2)(iii) of this section on an aggregate use basis for both fluorinated GHGs if one of the fluorinated GHGs selected for comparison corresponds to the largest quantity, on a mass basis, of fluorinated GHGs used at each fab that requires apportionment during the reporting year.

(iii) You must demonstrate that the comparison performed for the largest quantity of gas(es), on a mass basis, consumed in the fab in paragraph (c)(2)(ii) of this section, does not result in a difference between the actual and modeled gas consumption that exceeds 20 percent relative to actual gas consumption, reported to two significant figures using standard rounding conventions.

(iv) If you are required to apportion gas consumption and you use the procedures in §98.93(i) to calculate annual emissions from a fab, you must verify your apportioning factors using the procedures in paragraphs (c)(2)(ii) and (iii) of this section such that the time period specified in paragraph (c)(2)(i) of this section and the last day you perform the sampling events specified under §98.93(i)(3) occur in the same accounting month.

(v) If your facility has multiple fabs with a single centralized fluorinated-GHG supply system, you must verify that your apportioning model can apportion fluorinated GHG consumption among the fabs by adhering to the procedures in paragraphs (c)(2)(ii) through (c)(2)(iv) of this section.

(3) As an alternative to developing apportioning factors for fluorinated GHG and N_2O consumption using a fab-specific engineering model, you may develop apportioning factors through the use of direct measurement using gas flow meters and weigh scales to measure process sub-type, process type, stack system, or fab-specific input gas consumption. You may use a combination of apportioning factors developed using a fab-specific engineering model and apportioning factors developed through the use of direct measurement, provided this is documented in your site GHG Monitoring Plan as required under 98.3(g)(5).

(d)–(e) [Reserved]

(f) If your fab employs abatement systems and you elect to reflect emission reductions due to these systems, or if your fab employs abatement systems designed for fluorinated GHG abatement and you elect to calculate fluorinated GHG emissions using the stack test method under 98.93(i), you must comply with the requirements of paragraphs (f)(1) through (f)(3) of this section. If you use an average of properly measured destruction or removal efficiencies for a gas and process sub-type or process type combination, as applicable, in your emission calculations under §98.93(a), (b), and/or (i), you must also adhere to procedures in paragraph (f)(4) of this section.

(1) You must certify and document that the abatement systems are properly installed, operated, and maintained according to the site maintenance plan for abatement systems that is developed and maintained in your records as specified in §98.97(d)(9).

(2) You must calculate and document the uptime of abatement systems using Equation I–15 or I–23 of this subpart, as applicable.

(3) If you use default destruction and removal efficiency values in your emissions calculations under §98.93(a), (b), and/or (i), you must certify and document that the abatement systems at your facility for which you use default destruction or removal efficiency values are specifically designed for fluorinated GHG or N_2O abatement, as applicable. If you elect to calculate fluorinated GHG emissions using the stack test method under §98.93(i), you must also certify that you have included and accounted for all abatement systems designed for fluorinated GHG abatement and any respective downtime in your emissions calculations under §98.93(i)(3).

(4) If you do not use the default destruction or removal efficiency values in Table I–16 of this subpart to calculate and report controlled emissions, including situations in which your fab employs abatement systems not specifically designed for fluorinated GHG or N_2O abatement and you elect to reflect emission reduction due to these systems, you must use an average of properly measured destruction or removal efficiencies for each gas and process sub-type or process type combination, as applicable, determined in accordance with procedures in paragraphs (f)(4)(i) through (vi) of this section. You must not use a default value from Table I–16 of this subpart for any abatement system not specifically designed for fluorinated GHG and N_2O abatement, or for any gas and process type combination for which you have measured the destruction or removal efficiency according to the requirements of paragraphs (f)(4)(i) through (vi) of this section.

(i) A properly measured destruction or removal efficiency value must be determined in accordance with EPA 430–R–10–003 (incorporated by reference, see § 98.7), or according to an alternative method approved by the Administrator (or authorized representative) as specified in paragraph (k) of this section. If you are measuring destruction or removal efficiency according to EPA 430–R–10–003 (incorporated by reference, see § 98.7), you may follow the alternative procedures specified in Appendix A to this subpart.

(ii) You must select and properly measure the destruction or removal efficiency for a random sample of abatement systems to include in a random sampling abatement system testing program in accordance with procedures in paragraphs (f)(4)(ii)(A) and (B) of this section.

(A) For the first 2 years for which your fab is required to report emissions of fluorinated GHG and N_2O, for each abatement system gas and process sub-type or process type combination, as applicable, a random sample of a minimum of 10 percent of installed abatement systems must be tested annually for a total of a minimum of 20 percent, or a minimum of 20 percent may be tested in the first year. For every 3-year period following the initial 2-year period, a random sample of at least 15 percent of installed abatement systems must be tested for each gas and process sub-type or process type combination; you may test 15-percent in the first year of the 3-year period, but you must test at least 5 percent each year until 15 percent are tested. For each 3-year period, you must determine the number of abatement systems to be tested based on the average number of abatement systems in service over the 3-year period. If the required percent of the total number of abatement systems to be tested for each gas and process sub-type or process type combination does not equate to a whole number, the number of systems to be tested must be determined by rounding up to the nearest integer. Except as provided in paragraph (f)(4)(v) of this section, you may not retest an abatement system for any gas and process sub-type or process type combination, as applicable, until all of the abatement systems for that gas and process sub-type or process type combination have been tested.

(B) If testing of a randomly selected abatement system would be disruptive to production, you may replace that system with another randomly selected system for testing and return the system to the sampling pool for subsequent testing. Any one abatement system must not be replaced by another randomly selected system for more than three consecutive selections. When you have to replace a system in one year, you may select that specific system to be tested in one of the next two sampling years so that you may plan testing of that abatement system to avoid disrupting production.

(iii) If you elect to take credit for abatement system destruction or removal efficiency before completing testing on 20 percent of the abatement systems for that gas and process sub-type or process type combination, as applicable, you must use default destruction or removal efficiencies for a gas and process type combination. You must not use a default value from Table I–16 of this subpart for any abatement system not specifically designed for fluorinated GHG and N_2O abatement, and must not take credit for abatement system destruction or removal efficiency before completing testing on 20 percent of the abatement systems for that gas and process sub-type or process type combination, as applicable. Following testing on 20 percent of abatement systems for that gas and process sub-type or process type combination, you must calculate the average destruction or removal efficiency as the arithmetic mean of all test results for that gas and process sub-type or process type combination, until you have tested at least 30 percent of all abatement systems for each gas and process sub-type or process type combination. After testing at least 30 percent of all systems for a gas and process sub-type or process type combination, you must use the arithmetic mean of the most recent 30 percent of systems tested as the average destruction or removal efficiency. You may include results of testing conducted on or after January 1, 2011 for use in determining the site-specific destruction or removal efficiency for a given gas and process sub-type or process type combination if the testing was conducted in accordance with the requirements of paragraph (f)(4)(i) of this section.

(iv) If a measured destruction or removal efficiency is below the manufacturer-claimed fluorinated GHG or N_2O destruction or removal efficiency for any abatement system specifically designed for fluorinated GHG or N_2O abatement and the abatement system is installed, operated, and maintained in accordance with the site maintenance plan for abatement systems that is developed and maintained in your records as specified in §98.97(d)(9), the measured destruction or removal efficiency must be included in the calculation of the destruction or removal efficiency value for that gas and process sub-type or process type.

(v) If a measured destruction or removal efficiency is below the manufacturer-claimed fluorinated GHG or N_2O destruction or removal efficiency for any abatement system specifically designed for fluorinated GHG or N_2O abatement and the abatement system is not installed, operated, or maintained in accordance with the site maintenance plan for abatement systems that is developed and maintained in your records as specified in §98.97(d)(9), you must implement corrective action and perform a retest to replace the measured value within the reporting year. In lieu of retesting within the reporting year, you may use the measured value in calculating the average destruction or removal efficiency for the reporting year, implement corrective action, and then include the same system in the next abatement system testing period in addition to the testing of randomly selected systems for that next testing period. Regardless of whether you use the lower measured destruction or removal efficiency and when you perform the retest of the abatement system, you must count the time that the abatement system is not operated and maintained according to the site maintenance plan for abatement systems as not being in operational mode for purposes of calculating abatement system uptime.

(vi) If your fab uses redundant abatement systems, you may account for the total abatement system uptime (that is, the time that at least one abatement system is in operational mode) calculated for a specific exhaust stream during the reporting year.

(g) You must adhere to the QA/QC procedures of this paragraph when calculating fluorinated GHG and N_2O emissions from electronics manufacturing production processes:

(1)–(2) [Reserved]

(3) Follow the QA/QC procedures in accordance with those in EPA 430–R–10–003 (incorporated by reference, see §98.7), or the applicable QA/QC procedures specified in an alternative method approved by the Administrator (or authorized representative) according to paragraph (k) of this section, when calculating abatement systems destruction or removal efficiencies. If you are measuring destruction or removal efficiency according to EPA 430–R–10–003 (incorporated by reference, see §98.7), and you elect to follow the alternative procedures specified in Appendix A to this subpart according to paragraph (f)(4)(i) of this section, you must follow any additional QA/QC procedures specified in Appendix A to this subpart.

(4) As part of normal operations for each fab, the inventory of gas stored in containers at the beginning of the reporting year must be the same as the inventory of gas stored in containers at the end of the previous reporting year. You must maintain records documenting the year end and year beginning inventories under §98.97(a).

(h) You must adhere to the QA/QC procedures of this paragraph (h) when calculating annual gas consumption for each fluorinated GHG and N_2O used at each fab and emissions from the use of each fluorinated heat transfer fluid on a fab basis.

(1) Review all inputs to Equations I–11 and I–16 of this subpart to ensure that all inputs and outputs are accounted for.

(2) Do not enter negative inputs into the mass balance Equations I–11 and I–16 of this subpart and ensure that no negative emissions are calculated.

(3) Ensure that the inventory at the beginning of one reporting year is identical to the inventory at the end of the

previous reporting year. You must maintain records documenting the year end and year beginning inventories under § 98.97(a) and (r).

(4) Ensure that the total quantity of gas i in containers in service at the end of a reporting year is accounted for as if the in-service containers were full for Equation I–11 of this subpart. Ensure also that the same quantity is accounted for in the inventory of input gas i stored in containers at the beginning of the subsequent reporting year.

(i) All flow meters, weigh scales, pressure gauges, and thermometers used to measure quantities that are monitored under this section or used in calculations under § 98.93 must meet the calibration and accuracy requirements specified in § 98.3(i).

(j) *Stack test methodology.* For each fab for which you calculate annual emissions for any fluorinated GHG emitted from your facility using the stack test method according to the procedure specified in § 98.93(i)(3), you must adhere to the requirements in paragraphs (j)(1) through (8) of this section. You may request approval to use an alternative stack test method and procedure according to paragraph (k) of this section.

(1) *Stack system testing.* Conduct an emissions test for each applicable stack system according to the procedures in paragraphs (j)(1)(i) through (iv) of this section.

(i) You must conduct an emission test during which the fab is operating at a representative operating level, as defined in § 98.98, and with the abatement systems connected to the stack system being tested operating with at least 90 percent uptime, averaged over all abatement systems, during the 8-hour (or longer) period for each stack system, or at no less than 90 percent of the abatement system uptime rate measured over the previous reporting year, averaged over all abatement systems.

(ii) You must measure for the expected and possible by-products identified in Table I–17 of this subpart and those fluorinated GHGs used as input fluorinated GHG in process tools vented to the stack system, except for any intermittent low-use fluorinated GHG as defined in § 98.98. You must calculate annual emissions of intermittent low-use fluorinated GHGs by adhering to the procedures in § 98.93(i)(4)(i).

(iii) If a fluorinated GHG being consumed in the reporting year was not being consumed during the stack testing and does not meet the definition of intermittent low-use fluorinated GHG in § 98.98, then you must test the stack systems associated with the use of that fluorinated GHG at a time when that gas is in use at a magnitude that would allow you to determine an emission factor for that gas. If a fluorinated GHG consumed in the reporting year was not being consumed during the stack testing and is no longer in use by your fab (e.g., use of the gas has become obsolete or has been discontinued), then you must calculate annual emissions for that fluorinated GHG according to the procedure specified in § 98.93(i)(4).

(iv) Although all applicable stack systems are not required to be tested simultaneously, you must certify that no significant changes in stack flow configuration occur between tests conducted for any particular fab in a reporting year. You must certify that no more than 10 percent of the total number of fluorinated GHG emitting process tools are connected or disconnected from a stack system during testing. You must also certify that no process tools that were in operation at the start of the test period have been moved to a different stack system during the test period (i.e., during or in between testing of individual stack systems) and that no point-of-use abatement systems have been permanently removed from service during the test period. You must document any changes in stack flow configuration in the emissions test data and report required to be kept as records under § 98.97(i)(4).

(2) *Test methods and procedures.* You must adhere to the applicable test methods and procedures specified in Table I–9 to this subpart, or adhere to an alternative method approved by the Administrator (or authorized representative) according to paragraph (k) of this section. If you select Method 320 of 40 CFR part 63, Appendix A to measure the concentration of each fluorinated GHG in the stack system,

you must complete a method validation according to Section 13 of Method 320 of 40 CFR part 63, Appendix A for each FTIR system (hardware and software) and each tester (testing company). Method 320 validation is necessary when any change occurs in instrumentation, tester (i.e., testing company), or stack condition (e.g., acid gas vs. base). Measurement of new compounds require validation for those compounds according to Section 13 of Method 320 of 40 CFR part 63, Appendix A. The field detection limits achieved under your test methods and procedures must fall at or below the maximum field detection limits specified in Table I–10 to this subpart.

(3) *Fab-specific fluorinated GHG consumption measurements.* You must determine the amount of each fluorinated GHG consumed by each fab during the sampling period for all process tools connected to the stack systems tested under § 98.93(i)(3), according to the procedures in paragraphs (j)(3)(i) and (ii) of this section. This determination must include apportioning gas consumption between stack systems that are being tested and those that are not tested under § 98.93(i)(2).

(i) Measure fluorinated GHG consumption using gas flow meters, scales, or pressure measurements. Measure the mass or pressure, as applicable, at the beginning and end of the sampling period and when containers are changed out. If you elect to measure gas consumption using pressure (i.e., because the gas is stored in a location above its critical temperature) you must estimate consumption as specified in paragraphs (j)(3)(i)(A) and (B) of this section.

(A) For each fluorinated GHG, you must either measure the temperature of the fluorinated GHG container(s) when the sampling periods begin and end and when containers are changed out, or measure the temperature of the fluorinated GHG container(s) every hour for the duration of the sampling period. Temperature measurements of the immediate vicinity of the containers (e.g., in the same room, near the containers) shall be considered temperature measurements of the containers.

(B) Convert the sampling period-beginning, sampling period-ending, and container change-out pressures to masses using Equation I–25 of this subpart, with the appropriate Z value selected based upon the properties of the gas (e.g., the Z value yielded by the Redlich, Kwong, Soave equation of state with appropriate values for that gas). Apply the temperatures measured at or nearest to the beginning and end of the sampling period and to the time(s) when containers are changed out, as applicable. For each gas, the consumption during the sampling period is the difference between the masses of the containers of that gas at the beginning and at the end of the sampling period, summed across containers, including containers that are changed out.

(ii) For each fluorinated GHG gas for which consumption is too low to be accurately measured during the sampling period using gas flow meters, scales, or pressure measurements as specified in paragraph (j)(3)(i) of this section, you must follow at least one of the procedures listed in paragraph (j)(3)(ii)(A) through (C) of this section to obtain a consumption measurement.

(A) Draw the gas from a single gas container if it is normally supplied from multiple containers connected by a shared manifold.

(B) Calculate consumption from prorated long-term consumption data (for example, calculate and use hourly consumption rates from monthly consumption data).

(C) Increase the duration of the sampling period for consumption measurement beyond the minimum duration specified in Table I–9 of this subpart.

(4) *Emission test results.* The results of an emission test must include the analysis of samples, number of test runs, the average emission factor for each fluorinated GHG measured, the analytical method used, calculation of emissions, the fluorinated GHGs consumed during the sampling period, an identification of the stack systems tested, and the fluorinated GHGs that were included in the test. The emissions test report must contain all information and data used to derive the fab-specific emission factor.

(5) *Emissions testing frequency.* You must conduct emissions testing to develop fab-specific emission factors on a frequency according to the procedures in paragraph (j)(5)(i) or (ii) of this section.

(i) *Annual testing.* You must conduct an annual emissions test for each stack system for which emissions testing is required under § 98.93(i)(3), unless you meet the criteria in paragraph (j)(5)(ii) of this section to skip annual testing. Each set of emissions testing for a stack system must be separated by a period of at least 2 months.

(ii) *Criteria to test less frequently.* After the first 3 years of annual testing, you may calculate the relative standard deviation of the emission factors for each fluorinated GHG included in the test and use that analysis to determine the frequency of any future testing. As an alternative, you may conduct all three tests in less than 3 calendar years for purposes of this paragraph (j)(5)(ii), but this does not relieve you of the obligation to conduct subsequent annual testing if you do not meet the criteria to test less frequently. If the criteria specified in paragraphs (j)(5)(ii)(A) and (B) of this section are met, you may use the arithmetic average of the three emission factors for each fluorinated GHG and fluorinated GHG by-product for the current year and the next 4 years with no further testing unless your fab operations are changed in way that triggers the re-test criteria in paragraph (j)(8) of this section. In the fifth year following the last stack test included in the previous average, you must test each of the stack systems for which testing is required and repeat the relative standard deviation analysis using the results of the most recent three tests (i.e., the new test and the two previous tests conducted prior to the 4 year period). If the criteria specified in paragraphs (j)(5)(ii)(A) and (B) of this section are not met, you must use the emission factors developed from the most recent testing and continue annual testing. You may conduct more than one test in the same year, but each set of emissions testing for a stack system must be separated by a period of at least 2 months. You may repeat the relative standard deviation analysis using the most recent three tests, including those tests conducted prior to the 4 year period, to determine if you are exempt from testing for the next 4 years.

(A) The relative standard deviation of the total CO_2e emission factors calculated from each of the three tests (expressed as the total CO_2e fluorinated GHG emissions of the fab divided by the total CO_2e fluorinated GHG use of the fab) is less than or equal to 15 percent.

(B) The relative standard deviation for all single fluorinated GHGs that individually accounted for 5 percent or more of CO_2e emissions were less than 20 percent.

(C) For those fluorinated GHG that do not have GWP values listed in Table A–1 to subpart A of this part, you must use a GWP value of 2,000 in calculating CO_2e in paragraphs (j)(5)(ii)(A) and (B) of this section.

(6) *Subsequent measurements.* You must make an annual determination of each stack system's exemption status under § 98.93(i)(2) by March 31 each year. If a stack system that was previously not required to be tested per § 98.93(i)(2), no longer meets the criteria in § 98.93(i)(2), you must conduct the emissions testing for the stack system during the current reporting and develop the fab-specific emission factor from the emissions testing.

(7) *Previous measurements.* You may include the results of emissions testing conducted on or after January 1, 2011 for use in the relative standard deviation calculation in paragraph (j)(5)(ii) of this section if the previous results were determined using a method meeting the requirements in paragraph (j)(2) of this section. You may request approval to use results of emissions testing conducted between January 1, 2011 and January 1, 2014 using a method that deviated from the requirements in paragraph (j)(2) of this section by adhering to the requirements in paragraphs (j)(7)(i) through (j)(7)(iv) of this section.

(i) Notify the Administrator (or an authorized representative) of your intention to use the results of the previous emissions testing. You must include in the notification the data and results you intend to use for meeting either reporting or recordkeeping requirements, a description of the method, and any deviations from the requirements in paragraph (j)(2) of this section. Your description must include an explanation of how any deviations do not affect the quality of the data collected.

(ii) The Administrator will review the information submitted under paragraph (j)(7)(i) and determine whether the results of the previous emissions testing are adequate and issue an approval or disapproval of the use of the results within 120 days of the date on which you submit the notification specified in paragraph (j)(7)(i) of this section.

(iii) If the Administrator finds reasonable grounds to disapprove the results of the previous emissions testing, the Administrator may request that you provide additional information to support the use of the results of the previous emissions testing. Failure to respond to any request made by the Administrator does not affect the 120 day deadline specified in paragraph (j)(7)(ii) of this section.

(iv) Neither the approval process nor the failure to obtain approval for the use of results from previous emissions testing shall abrogate your responsibility to comply with the requirements of this subpart.

(8) *Scenarios that require a stack system to be re-tested.* By March 31 of each reporting year, you must evaluate and determine whether any changes to your fab operations meet the criteria specified in paragraphs (j)(8)(i) through (vi) of this section. If any of the scenarios specified in paragraph (j)(8)(i) through (vi) of this section occur, you must perform a re-test of any applicable stack system, irrespective of whether you have met the criteria for less frequent testing in paragraph (j)(5)(ii) of this section, before the end of the year in which the evaluation was completed. You must adhere to the methods and procedures specified in §98.93(i)(3) for performing a stack system emissions test and calculating emissions. If you meet the criteria for less frequent testing in paragraph (j)(5)(ii), and you are required to perform a re-test as specified in paragraph (j)(8)(i) through (vi) of this section, the requirement to perform a re-test does not extend the date of the next scheduled test that was established prior to meeting the requirement to perform a re-test. If the criteria specified in paragraph (j)(5)(ii) of this section are not met using the results from the re-test and the two most recent stack tests, you must use the emission factors developed from the most recent testing to calculate emissions and resume annual testing. You may resume testing less frequently according to your original schedule if the criteria specified in paragraph (j)(5)(ii) of this section are met using the most recent three tests.

(i) Annual consumption of a fluorinated GHG used during the most recent emissions test (expressed in CO_2e) changes by more than 10 percent of the total annual fluorinated GHG consumption, relative to gas consumption in CO_2e for that gas during the year of the most recent emissions test (for example, if the use of a single gas goes from 25 percent of CO_2e to greater than 35 percent of CO_2e, this change would trigger a re-test). For those fluorinated GHGs that do not have GWP values listed in Table A–1 to subpart A of this part, you must use a GWP value of 2,000 in calculating CO_2e for purposes of this paragraph.

(ii) A change in the consumption of an intermittent low-use fluorinated GHG (as defined in §98.98) that was not used during the emissions test and not reflected in the fab-specific emission factor, such that it no longer meets the definition of an intermittent low-use fluorinated GHG.

(iii) A decrease by more than 10 percent in the fraction of tools with abatement systems, compared to the number during the most recent emissions test.

(iv) A change in the wafer size manufactured by the fab since the most recent emissions test.

(v) A stack system that formerly met the criteria specified under §98.93(i)(2) for not being subject to testing no longer meets those criteria.

(vi) If a fluorinated GHG being consumed in the reporting year was not being consumed during the stack test and does not meet the definition of intermittent, low-use fluorinated GHG in §98.98, then you must test the stack systems associated with the use of that fluorinated GHG at a time when that gas is in use as required in paragraph (j)(1)(iii) of this section.

(k) You may request approval to use an alternative stack test method and procedure or to use an alternative method to determine abatement system destruction or removal efficiency by adhering to the requirements in paragraphs (k)(1) through (6) of this section. An alternative method is any method of sampling and analyzing for a fluorinated GHG or N_2O, or the determination of parameters other than concentration, for example, flow measurements, that is not a method specified in this subpart and that has been demonstrated to the Administrator's satisfaction, using Method 301 in appendix A of part 63, to produce results adequate for the Administrator's determination that it may be used in place of a method specified elsewhere in this subpart.

(1) You may use an alternative method from that specified in this subpart provided that you:

(i) Notify the Administrator (or an authorized representative) of your intention to use an alternative method. You must include in the notification a site-specific test plan describing the alternative method and procedures (the alternative test plan), the range of test conditions over which the validation is intended to be applicable, and an alternative means of calculating the fab-level fluorinated GHG or N_2O emissions or determining the abatement system destruction or removal efficiency if the Administrator denies the use of the results of the alternative method under paragraph (k)(2) or (3) of this section.

(ii) Use Method 301 in appendix A of part 63 of this chapter to validate the alternative method. This may include the use of only portions of specific procedures of Method 301 if use of such procedures are sufficient to validate the alternative method; and

(iii) Submit the results of the Method 301 validation process along with the notification of intention and the rationale for not using the specified method.

(2) The Administrator will determine whether the validation of the proposed alternative method is adequate and issue an approval or disapproval of the alternative test plan within 120 days of the date on which you submit the notification and alternative test plan specified in paragraph (k)(1) of this section. If the Administrator approves the alternative test plan, you are authorized to use the alternative method(s) in place of the methods described in paragraph (f)(4)(i) of this section for measuring destruction or removal efficiency or paragraph (j) of this section for conducting the stack test, as applicable, taking into account the Administrator's comments on the alternative test plan. Notwithstanding the requirement in the preceding sentence, you may at any time prior to the Administrator's approval or disapproval proceed to conduct the stack test using the methods specified in paragraph (j) of this section or the destruction or removal efficiency determination specified in (f)(4)(i) of this section if you use a method specified in this subpart instead of the requested alternative. If an alternative test plan is not approved and you still want to use an alternative method, you must recommence the process to have an alternative test method approved starting with the notification of intent to use an alternative test method specified in paragraph (k)(1)(i) of this section.

(3) You must report the results of stack testing or destruction or removal efficiency determination using the alternative method and procedure specified in the approved alternative test plan. You must include in your report for an alternative stack test method and for an alternative abatement system destruction or removal efficiency determination the information specified in paragraph (j)(4) of this section, including all methods, calculations and data used to determine the fluorinated GHG emission factor or the abatement system destruction or removal efficiency. The Administrator will review the results of the test using the alternative methods and procedure and then approve or deny the use of the results of the alternative test method and procedure no later than 120 days after they are submitted to EPA.

(4) If the Administrator finds reasonable grounds to dispute the results obtained by an alternative method for the purposes of determining

fluorinated GHG emissions or destruction or removal efficiency of an abatement system, the Administrator may require the use of another method specified in this subpart.

(5) Once the Administrator has approved the use of the alternative method for the purposes of determining fluorinated GHG emissions for specific fluorinated GHGs and types of stack systems or abatement system destruction or removal efficiency, that method may be used at any other facility for the same fluorinated GHGs and types of stack systems, or fluorinated GHGs and abatement systems, if the approved conditions apply to that facility. In granting approval, the Administrator may limit the range of test conditions and emission characteristics for which that approval is granted and under which the alternative method may be used without seeking approval under paragraphs (k)(1) through (4) of this section. The Administrator will specify those limitations, if any, in the approval of the alternative method.

(6) Neither the validation and approval process nor the failure to validate or obtain approval of an alternative method shall abrogate your responsibility to comply with the requirements of this subpart.

[75 FR 74818, Dec. 1, 2010, as amended at 76 FR 36342, June 22, 2011; 76 FR 59551, Sept. 27, 2011; 77 FR 10380, Feb. 22, 2012; 77 FR 48089, Aug. 13, 2012; 78 FR 68209, Nov. 13, 2013]

§98.95 Procedures for estimating missing data.

(a) Except as provided in paragraph (b) of this section, a complete record of all measured parameters used in the fluorinated GHG and N_2O emissions calculations in §98.93 and §98.94 is required.

(b) If you use fluorinated heat transfer fluids at your facility and are missing data for one or more of the parameters in Equation I–16 of this subpart, you must estimate fluorinated heat transfer fluid emissions using the arithmetic average of the emission rates for the reporting year immediately preceding the period of missing data and the months immediately following the period of missing data. Alternatively, you may estimate missing information using records from the fluorinated heat transfer fluid supplier. You must document the method used and values used for all missing data values.

[75 FR 74818, Dec. 1, 2010, as amended at 77 FR 10381, Feb. 22, 2012]

§98.96 Data reporting requirements.

In addition to the information required by §98.3(c), you must include in each annual report the following information for each electronics manufacturing facility:

(a) Annual manufacturing capacity of each fab at your facility used to determine the annual manufacturing capacity of your facility in Equation I–5 of this subpart.

(b) For facilities that manufacture semiconductors, the diameter of wafers manufactured at each fab at your facility (mm).

(c) Annual emissions, on a fab basis as described in paragraph (c)(1) through (5) of this section.

(1) When you use the procedures specified in §98.93(a) of this subpart, each fluorinated GHG emitted from each process type for which your fab is required to calculate emissions as calculated in Equations I–6 and I–7 of this subpart.

(2) Each fluorinated GHG emitted from each process type or process subtype as calculated in Equations I–8 and I–9 of this subpart, as applicable.

(3) N_2O emitted from all chemical vapor deposition processes and N_2O emitted from the aggregate of other N_2O-using manufacturing processes as calculated in Equation I–10 of this subpart.

(4) Each fluorinated heat transfer fluid emitted as calculated in Equation 1–16 of this subpart.

(5) When you use the procedures specified in §98.93(i) of this subpart, annual emissions of each fluorinated GHG, on a fab basis.

(d) The method of emissions calculation used in §98.93.

(e) Annual production in terms of substrate surface area (e.g., silicon, PV-cell, glass).

(f)–(l) [Reserved]

(m) For the fab-specific apportioning model used to apportion fluorinated GHG and N_2O consumption under §98.94(c), the following information to determine it is verified in accordance with procedures in § 98.94(c)(1) and (2):

(1) Identification of the quantifiable metric used in your fab-specific engineering model to apportion gas consumption for each fab, and/or an indication if direct measurements were used in addition to, or instead of, a quantifiable metric.

(2) The start and end dates selected under § 98.94(c)(2)(i).

(3) Certification that the gas(es) you selected under § 98.94(c)(2)(ii) for each fab corresponds to the largest quantity(ies) consumed, on a mass basis, of fluorinated GHG used at your fab during the reporting year for which you are required to apportion.

(4) The result of the calculation comparing the actual and modeled gas consumption under § 98.94(c)(2)(iii) and (iv), as applicable.

(5) If you are required to apportion fluorinated GHG consumption between fabs as required by § 98.94(c)(2)(v), certification that the gas(es) you selected under § 98.94(c)(2)(ii) corresponds to the largest quantity(ies) consumed on a mass basis, of fluorinated GHG used at your facility during the reporting year for which you are required to apportion.

(n)–(o) [Reserved]

(p) Inventory and description of all abatement systems through which fluorinated GHGs or N_2O flow at your facility and for which you are claiming destruction or removal efficiency, including:

(1) The number of abatement systems controlling emissions for each process sub-type, or process type, as applicable, for each gas used in the process sub-type or process type.

(2) The basis of the destruction or removal efficiency being used (default or site specific measurement according to § 98.94(f)(4)(i)) for each process sub-type or process type and for each gas.

(q) For all abatement systems through which fluorinated GHGs or N_2O flow at your facility, for which you are reporting controlled emissions, the following:

(1) Certification that all abatement systems at the facility have been installed, maintained, and operated in accordance with the site maintenance plan for abatement systems that is developed and maintained in your records as specified in § 98.97(d)(9).

(2) If you use default destruction or removal efficiency values in your emissions calculations under § 98.93(a), (b), or (i), certification that the site maintenance plan for abatement systems for which emissions are being reported contains manufacturer's recommendations and specifications for installation, operation, and maintenance for each abatement system.

(3) If you use default destruction or removal efficiency values in your emissions calculations under § 98.93(a), (b), and/or (i), certification that the abatement systems for which emissions are being reported were specifically designed for fluorinated GHG or N_2O abatement, as applicable. You must support this certification by providing abatement system supplier documentation stating that the system was designed for fluorinated GHG or N_2O abatement, as applicable.

(4) For all stack systems for which you calculate fluorinated GHG emissions according to the procedures specified in § 98.93(i)(3), certification that you have included and accounted for all abatement systems and any respective downtime in your emissions calculations under § 98.93(i)(3).

(r) You must report an effective fab-wide destruction or removal efficiency value for each fab at your facility calculated using Equation I–26, I–27, and I–28 of this subpart, as appropriate.

$$DRE_{FAB} = 1 - \left[\frac{\sum_i FGHG_i * GWP_i + \sum_j N_2O_j * GWP_{N2O}}{UAFGHG + SFGHG + \sum_j C_{N2O,j} * (1 - U_{N2O,j}) * GWP_{N2O}} \right] \qquad \text{(Eq. I-26)}$$

Where:

DRE_{FAB} = Fab-wide effective destruction or removal efficiency value, expressed as a decimal fraction.

$FGHG_i$ = Total emissions of each fluorinated GHG i emitted from electronics manufacturing processes in the fab, calculated according to the procedures in § 98.93.

N_2O_j = Emissions of N_2O from each N_2O-emitting electronics manufacturing process j in the fab, expressed in metric ton CO_2 equivalents, calculated according to the procedures in § 98.93.

UAFGHG = Total unabated emissions of fluorinated GHG emitted from electronics manufacturing processes in the fab, expressed in metric ton CO_2 equivalents as calculated in Equation I–27 of this subpart.

SFGHG = Total unabated emissions of fluorinated GHG emitted from electronics manufacturing processes in the fab, expressed in metric ton CO_2 equivalents, as calculated in Equation I–28 of this subpart.

$C_{N_2O,j}$ = Consumption of N_2O in each N_2O emitting process j, expressed in metric ton CO_2 equivalents.

$1–U_{N_2O,j}$ = N_2O emission factor for each N_2O emitting process j from Table I–8 of this subpart.

GWP_i = GWP of emitted fluorinated GHG i from Table A–1 of this part. For those fluorinated GHGs for which Table A–1 to subpart A of this part does not define a GWP value, use a GWP value of 2,000 for purposes of this equation.

GWP_{N_2O} = GWP of N_2O from Table A–1 of this part.

i = Fluorinated GHG.

j = Process Type.

(1) Use Equation I–27 of this subpart to calculate total unabated emissions, in metric tons CO_2e, of all fluorinated GHG emitted from electronics manufacturing processes whose emissions of fluorinated GHG you calculated according to the default utilization and by-product formation rate procedures in § 98.93(a) or § 98.93(i)(4). For each fluorinated GHG i in process j, use the same consumption (C_{ij}), emission factors ($1-U_{ij}$), and by-product formation rates (B_{ijk}) to calculate unabated emissions as you used to calculate emissions in § 98.93(a) or § 98.93(i)(4).

$$UAFGHG = \sum_i \sum_j C_{ij} * (1 - U_{ij}) * GWP_i + \sum_i \sum_j C_{ij} * B_{ijk} * GWP_k \qquad \text{(Eq. I-27)}$$

Where:

UAFGHG = Total unabated emissions of fluorinated GHG emitted from electronics manufacturing processes in the fab, expressed in metric ton CO_2e for which you calculated total emission according to the procedures in § 98.93(a) or § 98.93(i)(4).

C_{ij} = Total consumption of fluorinated GHG i, apportioned to process j, expressed in metric ton CO_2e, which you used to calculate total emissions according to the procedures in § 98.93(a) or § 98.93(i)(4).

U_{ij} = Process utilization rate for fluorinated GHG i, process type j, which you used to calculate total emissions according to the procedures in § 98.93(a) or § 98.93(i)(4).

GWP_i = GWP of emitted fluorinated GHG i from Table A–1 of this part. For those fluorinated GHGs for which Table A–1 to subpart A of this part does not define a GWP value, use a GWP value of 2,000 for purposes of this equation.

GWP_k = GWP of emitted fluorinated GHG by-product k, from Table A–1 of this part. For those fluorinated GHGs for which Table A–1 to subpart A of this part does not define a GWP value, use a GWP value of 2,000 for purposes of this equation.

B_{ijk} = By-product formation rate of fluorinated GHG k created as a by-product per amount of fluorinated GHG input gas i (kg) consumed by process type j (kg).

i = Fluorinated GHG.

j = Process Type.

k = Fluorinated GHG by-product.

(2) Use Equation I–28 to calculate total unabated emissions, in metric ton CO_2e, of all fluorinated GHG emitted from electronics manufacturing processes whose emissions of fluorinated GHG you calculated according to the stack testing procedures in § 98.93(i)(3). For each set of processes, use the same input gas consumption (C_{if}), input gas emission factors (EF_{if}), by-product gas emission factors (EF_{kf}), fractions of tools abated (a_{if} and a_f), and destruction efficiencies (d_{if} and d_{kf}) to calculate unabated emissions as you used to calculate emissions.

$$SFGHG = \sum_i \left[\frac{EF_{if}}{\left(1-\left(a_{if} * d_{if}\right)\right)} * C_{if} * GWP_i \right] + \sum_k \left[\frac{EF_{kf}}{\left(1-\left(a_f * d_{kf}\right)\right)} * \sum_i C_{if} * GWP_k \right] \quad \text{Eq. I-28)}$$

Where:

SFGHG = Total unabated emissions of fluorinated GHG emitted from electronics manufacturing processes in the fab, expressed in metric ton CO_2e for which you calculated total emission according to the procedures in § 98.93(i)(3).

EF_{if} = Emission factor for fluorinated GHG input gas i, emitted from fab f, as calculated in Equation I–19 of this subpart (kg emitted/kg input gas consumed).

a_{if} = Fraction of fluorinated GHG input gas i used in fab f in tools with abatement systems (expressed as a decimal fraction).

d_{if} = Fraction of fluorinated GHG i destroyed or removed in abatement systems connected to process tools in fab f, which you used to calculate total emissions according to the procedures in § 98.93(i)(3) (expressed as a decimal fraction).

C_{if} = Total consumption of fluorinated GHG input gas i, of tools vented to stack systems that are tested, for fab f, for the reporting year, expressed in metric ton CO_2e, which you used to calculate total emissions according to the procedures in § 98.93(i)(3) (expressed as a decimal fraction).

EF_{kf} = Emission factor for fluorinated GHG by-product gas k, emitted from fab f, as calculated in Equation I–20 of this subpart (kg emitted/kg of all input gases consumed in tools vented to stack systems that are tested).

a_f = Fraction of input gases used in fab f in tools with abatement systems (expressed as a decimal fraction).

d_{kf} = Fraction of fluorinated GHG by-product k destroyed or removed in abatement systems connected to process tools in fab f, which you used to calculate total emissions according to the procedures in § 98.93(i)(3) (expressed as a decimal fraction).

GWP_i = GWP of emitted fluorinated GHG i from Table A–1 of this part. For those fluorinated GHGs for which Table A–1 of subpart A to this part does not define a GWP value, use a GWP value of 2,000 for purposes of this equation.

GWP_k = GWP of emitted fluorinated GHG by-product k, from Table A–1 of this part. For those fluorinated GHGs for which Table A–1 to subpart A of this part does not define a GWP value, use a GWP value of 2,000 for purposes of this equation.

i = Fluorinated GHG.

k = Fluorinated GHG by-product.

(s) Where missing data procedures were used to estimate inputs into the fluorinated heat transfer fluid mass balance equation under § 98.95(b), the number of times missing data procedures were followed in the reporting year and the method used to estimate the missing data.

(t)–(v) [Reserved]

(w) If you elect to calculate fab-level emissions of fluorinated GHG using the stack test methods specified in § 98.93(i), you must report the following in paragraphs (w)(1) and (2) for each stack system, in addition to the relevant data in paragraphs (a) through (v) of this section:

(1) The date of any stack testing conducted during the reporting year, and the identity of the stack system tested.

(2) An inventory of all stack systems from which process fluorinated GHG are emitted. For each stack system, indicate whether the stack system is among those for which stack testing was performed as per § 98.93(i)(3) or not performed as per § 98.93(i)(2).

(x) If the emissions you report under paragraph (c) of this section include emissions from research and development activities, as defined in § 98.6, report the approximate percentage of total GHG emissions, on a metric ton CO_2e basis, that are attributable to research and development activities, using the following ranges: less than 5 percent, 5 percent to less than 10 percent, 10 percent to less than 25 percent, 25 percent to less than 50 percent, 50 percent and higher. For those fluorinated GHG that do not have GWP values listed in Table A–1 of subpart A of this part, you must use a GWP value of 2,000 in calculating CO_2e for purposes of this paragraph.

(y) If your semiconductor manufacturing facility emits more than 40,000 metric ton CO_2e of GHG emissions, based on your most recently submitted annual report (beginning with the 2015 reporting year) as required in paragraph (c) of this section, from the electronics manufacturing processes subject to reporting under this subpart, you must prepare and submit a triennial (every 3 years) technology assessment report to the Administrator (or an authorized representative) that meets the requirements specified in paragraphs (y)(1) through (6) of this section. Any other semiconductor manufacturing facility may voluntarily submit this report to the Administrator.

(1) The first report must be submitted with the annual GHG emissions report that is due no later than March 31, 2017, and subsequent reports must be delivered every 3 years no later than March 31 of the year in which it is due.

(2) The report must include the information described in paragraphs (y)(2)(i) through (v) of this section.

(i) It must describe how the gases and technologies used in semiconductor manufacturing using 200 mm and 300 mm wafers in the United States have changed in the past 3 years and whether any of the identified changes are likely to have affected the emissions characteristics of semiconductor manufacturing processes in such a way that the default utilization and by-product formation rates or default destruction or removal efficiency factors of this subpart may need to be updated.

(ii) It must describe the effect on emissions of the implementation of new process technologies and/or finer line width processes in 200 mm and 300 mm technologies, the introduction of new tool platforms, and the introduction of new processes on previously tested platforms.

(iii) It must describe the status of implementing 450 mm wafer technology and the potential need to create or update default emission factors compared to 300 mm technology.

(iv) It must provide any utilization and by-product formation rates and/or destruction or removal efficiency data that have been collected in the previous 3 years that support the changes in semiconductor manufacturing processes described in the report.

(v) It must describe the use of a new gas, use of an existing gas in a new process type or sub-type, or a fundamental change in process technology.

(3) If, on the basis of the information reported in paragraph (y)(2) of this section, the report indicates that GHG emissions from semiconductor manufacturing may have changed from those represented by the default utilization and by-product formation rates in Tables I–3 or I–4, or the default destruction or removal efficiency values in Table I–16 of this subpart, the report must lay out a data gathering and analysis plan focused on the areas of potential change. The plan must describe the elements in paragraphs (y)(3)(i) and (ii).

(i) The testing of tools to determine the potential effect on current utilization and by-product formation rates and destruction or removal efficiency values under the new conditions.

(ii) A planned analysis of the effect on overall facility emissions using a representative gas-use profile for a 200 mm, 300 mm, or 450 mm fab (depending on which technology is under consideration).

(4) Multiple semiconductor manufacturing facilities may submit a single consolidated 3-year report as long as the facility identifying information in §98.3(c)(1) and the certification statement in §98.3(c)(9) is provided for each facility for which the consolidated report is submitted.

(5) The Administrator will review the report received and determine whether it is necessary to update the default utilization rates and by-product formation rates in Tables I–3, I–4, I–11, and I–12 of this subpart and default destruction or removal efficiency values in Table I–16 of this subpart based on the following:

(i) Whether the revised default utilization and by-product formation rates and destruction or removal efficiency values will result in a projected shift in emissions of 10 percent or greater.

(ii) Whether new platforms, processes, or facilities that are not captured in current default utilization and by-product formation rates and destruction or removal efficiency values should be included in revised values.

(iii) Whether new data are available that could expand the existing data set to include new gases, tools, or processes not included in the existing data set (i.e. gases, tools, or processes for which no data are currently available).

(6) The Administrator will review the reports within 120 days and will notify you of a determination whether it is necessary to update any default utilization and by-product formation rates and/or destruction or removal efficiency values. If the Administrator determines it is necessary to update default utilization and by-product formation rates and/or destruction or removal efficiency values, you will then have 180 days from the date you receive notice of the determination to execute the data collection and analysis plan described in the report and submit those data to the Administrator.

[75 FR 74818, Dec. 1, 2010, as amended at 77 FR 10381, Feb. 22, 2010; 78 FR 68215, Nov. 13, 2013; 78 FR 71954, Nov. 29, 2013]

§ 98.97 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) All data used and copies of calculations made as part of estimating gas consumption and emissions, including all spreadsheets.

(b) [Reserved]

(c) Documentation for the fab-specific engineering model used to apportion fluorinated GHG and N_2O consumption. This documentation must be part of your site GHG Monitoring Plan as required under § 98.3(g)(5). At a minimum, you must retain the following:

(1) A clear, detailed description of the fab-specific model, including how it was developed; the quantifiable metric used in the model; all sources of information, equations, and formulas, each with clear definitions of terms and variables; all apportioning factors used to apportion fluorinated GHG and N_2O; and a clear record of any changes made to the model while it was used to apportion fluorinated GHG and N_2O consumption across process sub-types, process types, tools with and without abatement systems, stack systems, and/or fabs.

(2) Sample calculations used for developing the gas apportioning factors (f_{ij}) for the two fluorinated GHGs used at your facility in the largest quantities, on a mass basis, during the reporting year.

(3) If you develop apportioning factors through the use of direct measurement according to § 98.94(c)(3), calculations and data used to develop each gas apportioning factor.

(4) Calculations and data used to determine and document that the fab was operating at representative operating levels, as defined in § 98.98, during the apportioning model verification specified in § 98.94(c).

(d) For all abatement systems through which fluorinated GHGs or N_2O flow at your facility, and for which you are reporting controlled emissions, the following in paragraphs (d)(1) to (9) of this section:

(1) Records of the information in paragraphs (d)(1)(i) though (iv) of this section:

(i) Documentation to certify that each abatement system or group of abatement systems is installed, maintained, and operated in accordance with the site maintenance plan for abatement systems that is specified in paragraph (d)(9) of this section.

(ii) Documentation from the abatement system supplier describing the abatement system's designed purpose and emission control capabilities for fluorinated GHG and N_2O for which the systems or group of systems is certified to abate, where available.

(iii) If you use default destruction or removal efficiency values in your emissions calculations under § 98.93(a), (b), and/or (i), certification that the abatement systems for which emissions are being reported were specifically designed for fluorinated GHG and N_2O abatement, as required under § 98.94(f)(3), and certification that the site maintenance plan includes manufacturer's recommendations and specifications for installation, operation, and maintenance for all applicable abatement systems.

(iv) Certification that you have included and accounted for all abatement systems and any respective downtime in your emissions calculations under § 98.93(i)(3), as required under § 98.94(f)(3).

(2) Abatement system calibration and maintenance records.

(3) Where the default destruction or removal efficiency value is used, documentation from the abatement system supplier describing the equipment's designed purpose and emission control capabilities for fluorinated GHG and N_2O.

(4) Where properly measured site-specific destruction or removal efficiencies are used to report emissions, the information in paragraphs (d)(4)(i) though (vi) of this section:

(i) Dated certification by the technician who made the measurement that the destruction or removal efficiency is calculated in accordance with methods in EPA 430–R–10–003 (incorporated by reference, see § 98.7) and, if applicable Appendix A of this subpart, or an alternative method approved by the Administrator as specified in § 98.94(k), complete documentation of the results of any initial and subsequent tests, the final report as specified in EPA 430–R–10–003 (incorporated by reference, see § 98.7) and, if applicable, the records and documentation specified in Appendix A of this subpart including the information required in paragraph (b)(7) of Appendix A of this subpart, or a final report as specified in an alternative method approved by the Administrator as specified in § 98.94(k).

(ii) The average destruction or removal efficiency of the abatement systems operating during the reporting year for each process type and gas combination.

(iii) A description of the calculation used to determine the average destruction or removal efficiency for each process type and gas combination, including all inputs to the calculation.

(iv) The records of destruction or removal efficiency measurements for abatement systems for all tests that have been used to determine the site-specific destruction or removal efficiencies currently being used.

(v) A description of the method used for randomly selecting abatement systems for testing.

(vi) The total number of systems for which destruction or removal efficiency was properly measured for each process type and gas combination for the reporting year.

(5) In addition to the inventory specified in § 98.96(p), the information in paragraphs (d)(5)(i) though (iii) of this section:

(i) The number of abatement systems of each manufacturer, and model numbers, and the manufacturer's claimed fluorinated GHG and N_2O destruction or removal efficiency, if any.

(ii) Records of destruction or removal efficiency measurements over the in-use life of each abatement system.

(iii) A description of the tool, with the process type or sub-type, for which the abatement system treats exhaust.

(6) Records of all inputs and results of calculations made accounting for the uptime of abatement systems used during the reporting year, in accordance with Equations I–15 or I–23 of this subpart, as applicable. The inputs should include an indication of whether each value for destruction or removal efficiency is a default value or a measured site-specific value.

(7) Records of all inputs and results of calculations made to determine the average weighted fraction of each gas destroyed or removed in the abatement systems for each stack system using Equation I–24 of this subpart, if applicable. The inputs should include an indication of whether each value for destruction or removal efficiency is a default value or a measured site-specific value.

(8) Records of all inputs and the results of the calculation of the facility-wide emission destruction or removal efficiency factor calculated according to Equations I–26, I–27, and I–28 of this subpart.

(9) A site maintenance plan for abatement systems, which must be maintained on-site at the facility as part of the facility's GHG Monitoring Plan as described in § 98.3(g)(5), and be developed and implemented according to paragraphs (d)(9)(i) through (iii) of this section.

(i) The site maintenance plan for abatement systems must be based on the abatement system manufacturer's recommendations and specifications for installation, operation, and maintenance if you use default destruction and removal efficiency values in your emissions calculations under § 98.93(a), (b), and/or (i). If the manufacturer's recommendations and specifications for installation, operation, and maintenance are not available, you cannot use default destruction and removal efficiency values in your emissions calculations under § 98.93(a), (b), and/or (i). If you use an average of properly measured destruction or removal efficiencies determined in accordance with the procedures in § 98.94(f)(4)(i) through (vi), the site maintenance plan for abatement systems must be based on the abatement system manufacturer's recommendations and specifications for installation, operation, and maintenance, where available. If you deviate from the manufacturer's recommendations and specifications, you must include documentation that demonstrates how the deviations do not negatively affect the performance or destruction or removal efficiency of the abatement systems.

(ii) The site maintenance plan for abatement systems must include a defined preventative maintenance process and checklist.

(iii) The site maintenance plan for abatement systems must include a corrective action process that you must follow whenever an abatement system is found to be not operating properly.

(e) Purchase records for gas purchased.

(f) Invoices for gas purchases and sales.

(g) Documents and records used to monitor and calculate abatement system uptime.

(h) GHG Monitoring Plans, as described in § 98.3(g)(5), must be completed by April 1, 2011. You must update your GHG Monitoring Plan to comply with § 98.94(c) consistent with the requirements in § 98.3(g)(5)(iii).

(i) Retain the following records for each fab for which you elect to calculate fab-level emissions of fluorinated GHG using the procedures specified in § 98.93(i)(3) or (4).

(1) Document all stack systems with emissions of fluorinated GHG that are less than 10,000 metric tons of CO_2e per year and all stack systems with emissions of 10,000 metric tons CO_2e per year or more. Include the data and calculation used to develop the preliminary estimate of emissions for each stack system.

(2) For each stack system, identify the method used to calculate annual emissions; either § 98.93(i)(3) or (4).

(3) The identity and total annual consumption of each gas identified as an intermittent low use fluorinated GHG as specified in § 98.93(i)(4)(i) and defined in § 98.98.

(4) The emissions test data and reports (see § 98.94(j)(4)) and the calculations used to determine the fab-specific emission factor, including the actual fab-specific emission factor, the average hourly emission rate of each fluorinated GHG from the stack system during the test and the stack system activity rate during the test. The report must also contain any changes in the stack system configuration during or between tests in a reporting year.

(5) The fab-specific emission factor and the calculations and data used to determine the fab-specific emission factor for each fluorinated GHG and by-product, as calculated using Equations I–19 and I–20 of § 98.93(i)(3).

(6) Calculations and data used to determine annual emissions of each fluorinated GHG for each fab.

(7) Calculations and data used to determine and document that the fab was operating at representative operating levels, as defined in § 98.98, during the stack testing period.

(8) A copy of the certification that no significant changes in stack system flow configuration occurred between tests conducted for any particular fab in a reporting year, as required by § 98.94(j)(1)(iv) and any calculations and data supporting the certification.

(9) The number of tools vented to each stack system in the fab.

(j) If you report the approximate percentage of total GHG emissions from research and development activities under § 98.96(x), documentation for the determination of the percentage of total emissions of each fluorinated GHG and/or N_2O attributable to research and development activities, as defined in § 98.6.

(k) Annual gas consumption for each fluorinated GHG and N_2O as calculated in Equation I–11 of this subpart, including where your fab used less than 50 kg of a particular fluorinated GHG or N_2O used at your facility for which you have not calculated emissions using

Equations I–6, I–7, I–8, I–9, I–10, I–21, or I–22 of this subpart, the chemical name of the GHG used, the annual consumption of the gas, and a brief description of its use.

(l) All inputs used to calculate gas consumption in Equation I–11 of this subpart, for each fluorinated GHG and N_2O used.

(m) Annual amount of each fluorinated GHG consumed for process sub-type, process type, stack system, or fab, as appropriate, and the annual amount of N_2O consumed for the aggregate of all chemical vapor deposition processes and for the aggregate of all other electronics manufacturing production processes, as calculated using Equation I–13 of this subpart.

(n) Disbursements for each fluorinated GHG and N_2O during the reporting year, as calculated using Equation I–12 of this subpart and all inputs used to calculate disbursements for each fluorinated GHG and N_2O used in Equation I–12 of this subpart, including all fab-wide gas-specific heel factors used for each fluorinated GHG and N_2O. If your fab used less than 50 kg of a particular fluorinated GHG during the reporting year, fab-wide gas-specific heel factors do not need to be reported for those gases.

(o) Fraction of each fluorinated GHG or N_2O fed into a process sub-type, process type, stack system, or fab that is fed into tools connected to abatement systems.

(p) Fraction of each fluorinated GHG or N_2O destroyed or removed in abatement systems connected to process tools where process sub-type, process type j is used, or to process tools vented to stack system j or fab f.

(q) All inputs and results of calculations made accounting for the uptime of abatement systems used during the reporting year, or during an emissions sampling period, in accordance with Equations I–15 and/or I–23 of this subpart, as applicable.

(r) For fluorinated heat transfer fluid emissions, inputs to the fluorinated heat transfer fluid mass balance equation, Equation I–16 of this subpart, for each fluorinated heat transfer fluid used.

(s) Where missing data procedures were used to estimate inputs into the fluorinated heat transfer fluid mass balance equation under § 98.95(b), the estimates of those data.

[75 FR 74818, Dec. 1, 2010, as amended at 78 FR 68218, Nov. 13, 2013

§ 98.98 Definitions.

Except as provided in this section, all of the terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part. If a conflict exists between a definition provided in this subpart and a definition provided in subpart A, the definition in this subpart takes precedence for the reporting requirements in this subpart.

Abatement system means a device or equipment that is designed to destroy or remove fluorinated GHGs or N_2O in exhaust streams from one or more electronics manufacturing production processes, or for which the destruction or removal efficiency for a fluorinated GHG or N_2O has been properly measured according to the procedures under § 98.94(f)(4), even if that abatement system is not designed to destroy or remove fluorinated GHGs or N_2O. The device or equipment is only an abatement system for the individual fluorinated GHGs or N_2O that it is designed to destroy or remove or for the individual fluorinated GHGs or N_2O for which destruction or removal efficiencies were properly measured according to the procedures under § 98.94(f)(4).

Actual gas consumption means the quantity of gas used during wafer/substrate processing over some period based on a measured change in gas container weight or gas container pressure or on a measured volume of gas.

By-product formation means the creation of fluorinated GHGs during electronics manufacturing production processes or the creation of fluorinated GHGs by an abatement system. Where the procedures in § 98.93(a) are used to calculate annual emissions, by-product formation is the ratio of the mass of the by-product formed to the mass flow of the input gas. Where the procedures in § 98.93(i) are used to calculate annual emissions, by-product formation is the ratio of the mass of the by-product formed to the total mass flow of all fluorinated GHG input gases.

Chamber cleaning is a process type that consists of the process sub-types defined in paragraphs (1) through (3) of this definition.

(1) In situ plasma process sub-type consists of the cleaning of thin-film production chambers, after processing substrates, with a fluorinated GHG cleaning reagent that is dissociated into its cleaning constituents by a plasma generated inside the chamber where the film is produced.

(2) Remote plasma process sub-type consists of the cleaning of thin-film production chambers, after processing substrates, with a fluorinated GHG cleaning reagent dissociated by a remotely located plasma source.

(3) In situ thermal process sub-type consists of the cleaning of thin-film production chambers, after processing substrates, with a fluorinated GHG cleaning reagent that is thermally dissociated into its cleaning constituents inside the chamber where thin films are produced.

Controlled emissions means the quantity of emissions that are released to the atmosphere after application of an emission control device (*e.g.*, abatement system).

Destruction or removal efficiency (DRE) means the efficiency of an abatement system to destroy or remove fluorinated GHGs, N_2O, or both. The destruction or removal efficiency is equal to one minus the ratio of the mass of all relevant GHGs exiting the abatement system to the mass of GHG entering the abatement system. When GHGs are formed in an abatement system, destruction or removal efficiency is expressed as one minus the ratio of amounts of exiting GHGs to the amounts entering the system in units of CO_2-equivalents (CO_2e).

Fab means the portion of an electronics manufacturing facility located in a separate physical structure that began manufacturing on a certain date.

Fluorinated heat transfer fluids means fluorinated GHGs used for temperature control, device testing, cleaning substrate surfaces and other parts, and soldering in certain types of electronics manufacturing production processes. Fluorinated heat transfer fluids do not include fluorinated GHGs used as lubricants or surfactants. For fluorinated heat transfer fluids under this subpart I, the lower vapor pressure limit of 1 mm Hg in absolute at 25 °C in the definition of *Fluorinated greenhouse gas* in § 98.6 shall not apply. Fluorinated heat transfer fluids used in the electronics manufacturing sector include, but are not limited to, perfluoropolyethers, perfluoroalkanes, perfluoroethers, tertiary perfluoroamines, and perfluorocyclic ethers.

Fully fluorinated GHGs means fluorinated GHGs that contain only single bonds and in which all available valence locations are filled by fluorine atoms. This includes, but is not limited to, saturated perfluorocarbons, SF_6, NF_3, SF_5CF_3, C_4F_8O, fully fluorinated linear, branched, and cyclic alkanes, fully fluorinated ethers, fully fluorinated tertiary amines, fully fluorinated aminoethers, and perfluoropolyethers.

Gas utilization means the fraction of input N_2O or fluorinated GHG converted to other substances during the etching, deposition, and/or wafer and chamber cleaning processes. Gas utilization is expressed as a rate or factor for specific electronics manufacturing process sub-types or process types.

Heel means the amount of gas that remains in a gas container after it is discharged or off-loaded; heel may vary by container type.

Input gas means a fluorinated GHG or N_2O used in one of the processes described in § 98.90(a)(1) through (4)

Intermittent low-use fluorinated GHG, for the purposes of determining fluorinated GHG emissions using the stack testing method, means a fluorinated GHG that meets all of the following:

(1) The fluorinated GHG is used by the fab but is not used during the period of stack testing for the fab/stack system.

(2) The emissions of the fluorinated GHG, estimated using the methods in § 98.93(i)(4) do not constitute more than 5 percent of the total fluorinated GHG emissions from the fab on a CO_2e basis.

(3) The sum of the emissions of all fluorinated GHGs that are considered intermittent low use gases does not exceed 10,000 metric tons CO_2e for the fab for that year, as calculated using the

procedures specified in § 98.93(i)(1) of this subpart.

(4) The fluorinated GHG is not an expected or possible by-product identified in Table I–17 of this subpart.

Maximum substrate starts means for the purposes of Equation I–5 of this subpart, the maximum quantity of substrates, expressed as surface area, that could be started each month during a reporting year based on the equipment installed in that facility and assuming that the installed equipment were fully utilized. Manufacturing equipment is considered installed when it is on the manufacturing floor and connected to required utilities.

Modeled gas consumed means the quantity of gas used during wafer/substrate processing over some period based on a verified facility-specific engineering model used to apportion gas consumption.

Nameplate capacity means the full and proper charge of chemical specified by the equipment manufacturer to achieve the equipment's specified performance. The nameplate capacity is typically indicated on the equipment's nameplate; it is not necessarily the actual charge, which may be influenced by leakage and other emissions.

Operational mode means the time in which an abatement system is properly installed, maintained, and operated according to the site maintenance plan for abatement systems as required in § 98.94(f)(1) and defined in § 98.97(d)(9). This includes being properly operated within the range of parameters as specified in the site maintenance plan for abatement systems.

Plasma etching is a process type that consists of any production process using fluorinated GHG reagents to selectively remove materials from a substrate during electronics manufacturing. The materials removed may include SiO_2, SiO_X-based or fully organic-based thin-film material, SiN, SiON, Si_3N_4, SiC, SiCO, SiCN, etc. (represented by the general chemical formula, $Si_wO_XN_yX_z$ where w, x, y and z are zero or integers and X may be some other element such as carbon), substrate, or metal films (such as aluminum or tungsten).

Process sub-type is a set of similar manufacturing steps, more closely related within a broad process type. For example, the chamber cleaning process type includes in-situ plasma chamber cleaning, remote plasma chamber cleaning, and in-situ thermal chamber cleaning sub-types.

Process types are broad groups of manufacturing steps used at a facility associated with substrate (e.g., wafer) processing during device manufacture for which fluorinated GHG emissions and fluorinated GHG consumption is calculated and reported. The process types are Plasma etching/Wafer Cleaning and Chamber cleaning.

Properly measured destruction or removal efficiency means destruction or removal efficiencies measured in accordance with EPA 430–R–10–003 (incorporated by reference, see § 98.7), and, if applicable, Appendix A to this subpart, or by an alternative method approved by the Administrator as specified in § 98.94(k).

The Random Sampling Abatement System Testing Program (RSASTP) means the required frequency for measuring the destruction or removal efficiencies of abatement systems in order to apply properly measured destruction or removal efficiencies to report controlled emissions.

Redundant abatement systems means a system that is specifically designed, installed and operated for the purpose of destroying fluorinated GHGs and N_2O gases, or for which the destruction or removal efficiency for a fluorinated GHG or N_2O has been properly measured according to the procedures under § 98.94(f)(4), and that is used as a backup to the main fluorinated GHGs and N_2O abatement system during those times when the main system is not functioning or operating in accordance with design and operating specifications.

Repeatable means that the variables used in the formulas for the facility's engineering model for gas apportioning factors are based on observable and measurable quantities that govern gas consumption rather than engineering judgment about those quantities or gas consumption.

Representative operating levels means (for purposes of verification of the apportionment model or for determining the appropriate conditions for stack testing) operating the fab, in terms of substrate starts for the period of testing or monitoring, at no less than 50 percent of installed production capacity or no less than 70 percent of the average production rate for the reporting year, where production rate for the reporting year is represented in average monthly substrate starts. For the purposes of stack testing, the period for determining the representative operating level must be the period ending on the same date on which testing is concluded.

Stack system means one or more stacks that are connected by a common header or manifold, through which a fluorinated GHG-containing gas stream originating from one or more fab processes is, or has the potential to be, released to the atmosphere. For purposes of this subpart, stack systems do not include emergency vents or bypass stacks through which emissions are not usually vented under typical operating conditions.

Trigger point for change out means the residual weight or pressure of a gas container type that a facility uses as an indicator that operators need to change out that gas container with a full container. The trigger point is not the actual residual weight or pressure of the gas remaining in the cylinder that has been replaced.

Unabated emissions means a gas stream containing fluorinated GHG or N_2O that has exited the process, but which has not yet been introduced into an abatement system to reduce the mass of fluorinated GHG or N_2O in the stream. If the emissions from the process are not routed to an abatement system, or are routed to an abatement device that is not in an operational mode, unabated emissions are those fluorinated GHG or N_2O released to the atmosphere.

Uptime means the ratio of the total time during which the abatement system is in an operational mode, to the total time during which production process tool(s) connected to that abatement system are normally in operation.

Wafer cleaning is a process type that consists of any production process using fluorinated GHG reagents to clean wafers at any step during production.

Wafer passes is a count of the number of times a wafer substrate is processed in a specific process sub-type, or type. The total number of wafer passes over a reporting year is the number of wafer passes per tool multiplied by the number of operational process tools in use during the reporting year.

Wafer starts means the number of fresh wafers that are introduced into the fabrication sequence each month. It includes test wafers, which means wafers that are exposed to all of the conditions of process characterization, including but not limited to actual etch conditions or actual film deposition conditions.

[75 FR 74818, Dec. 1, 2010, as amended at 77 FR 10381, Feb. 22, 2012; 78 FR 68220, Nov. 13, 2013]

TABLE I–1 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS FOR THRESHOLD APPLICABILITY DETERMINATION

Product type	Emission factors EF_i					
	CF_4	C_2F_6	CHF_3	C_3F_8	NF_3	SF_6
Semiconductors (kg/m^2)	0.90	1.00	0.04	0.05	0.04	0.20
LCD (g/m^2)	0.50	NA	NA	NA	0.90	4.00
MEMS (kg/m^2)	NA	NA	NA	NA	NA	1.02

NOTES: NA denotes not applicable based on currently available information.

[75 FR 74818, Dec. 1, 2010, as amended at 78 FR 68221, Nov. 13, 2013]

TABLE I–2 TO SUBPART I OF PART 98—EXAMPLES OF FLUORINATED GHGS USED BY THE ELECTRONICS INDUSTRY

Product type	Fluorinated GHGs and fluorinated heat transfer fluids used during manufacture
Electronics	CF_4, C_2F_6, C_3F_8, c-C_4F_8, c-C_4F_8O, C_4F_6, C_5F_8, CHF_3, CH_2F_2, NF_3, SF_6, and fluorinated HTFs (CF_3-(O-CF(CF_3)-CF_2)$_n$-(O-CF_2)$_m$-O-CF_3, C_nF_{2n+2}, $C_nF_{2n+1}(O)C_mF_{2m+1}$, $C_nF_{2n}O$, $(C_nF_{2n+1})_3N$).

[77 FR 10381, Feb. 22, 2012]

TABLE I–3 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR 150 MM AND 200 MM WAFER SIZES

Table I–3 to Subpart I of Part 98—Default Emission Factors (1–U_{ij}) for Gas Utilization Rates (U_{ij}) and By-Product Formation Rates (B_{ijk}) for Semiconductor Manufacturing for 150mm and 200 mm Wafer Sizes

Process Type/ Sub-Type	Process Gas i												
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_2HF_5	CH_3F	C_3F_8	C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
ETCHING/ WAFER CLEANING													
1-U_i	0.81	0.72	0.50	0.13	0.064	0.51	NA	0.14	0.19	0.55	0.17	0.072	NA
BCF_4	NA	0.10	0.085	0.079	0.077	NA	NA	0.11	0.0040	0.13	0.13	NA	NA
BC_2F_6	0.046	NA	0.030	0.025	0.024	NA	NA	0.037	0.025	0.11	0.11	0.014	NA
BC_4F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_4F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_5F_8	0.0012	NA	0.0012	NA	NA	NA	NA	0.0086	NA	NA	NA	NA	NA
$BCHF_3$	0.10	0.047	NA	0.049	NA	0.0034	NA	0.040	NA	0.0012	0.066	0.0039	NA
CHAMBER CLEANING													
In situ plasma cleaning													
1-U_i	0.92	0.55	NA	NA	NA	NA	0.40	0.10	0.18	NA	NA	NA	0.14
BCF_4	NA	0.21	NA	NA	NA	NA	0.20	0.11	0.050	NA	NA	NA	0.13
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.045
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Remote plasma cleaning													
1-U_i	NA	NA	NA	NA	NA	NA	NA	NA	0.018	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	0.015	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
In situ thermal cleaning													
1-U_i	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA = Not applicable; i.e., there are no applicable default emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

[78 FR 68221, Nov. 13, 2013]

TABLE I–4 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR 300 MM AND 450 MM WAFER SIZE

Table I–4 to Subpart I of Part 98–Default Emission Factors (1–U_{ij}) for Gas Utilization Rates (U_{ij}) and By-Product Formation Rates (B_{ijk}) for Semiconductor Manufacturing for 300 mm and 450 mm Wafer Size

Process Type/Sub-Type	**Process Gas i**											
	CF_4	C_2F_6	CHF_3	CH_2F_2	CH_3F	C_3F_8	C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
	ETCHING/WAFER CLEANING											
1-U_i	0.65	0.80	0.42	0.21	0.33	0.30	0.18	0.15	0.32	0.15	0.10	NA
BCF_4	NA	0.21	0.095	0.049	0.045	0.21	0.045	0.046	0.040	0.059	0.11	NA
BC_2F_6	0.079	NA	0.064	0.052	0.00087	0.18	0.031	0.045	0.044	0.074	0.083	NA
BC_4F_6	NA	NA	0.00010	NA	NA	NA	0.018	NA	NA	NA	NA	NA
BC_4F_8	0.00063	NA	0.00080	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00012	NA
$BCHF_3$	0.011	NA	NA	0.050	0.0057	0.012	0.027	0.025	0.0037	0.019	0.0069	NA
BCH_2F_2	NA	NA	0.0036	NA	0.0023	NA	0.0015	0.00086	0.000029	0.000030	NA	NA
BCH_3F	0.0080	NA	0.0080	0.0080	NA	0.00073	NA	0.0080	NA	NA	NA	NA
	CHAMBER CLEANING											
	In situ plasma cleaning											
1-U_i	NA	NA	NA	NA	NA	NA	NA	0.23	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	0.037	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	Remote plasma cleaning											
1-U_i	NA	NA	NA	NA	NA	0.063	NA	0.018	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	0.075	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Process Type/Sub-Type	Process Gas i											
	CF_4	C_2F_6	CHF_3	CH_2F_2	CH_3F	C_3F_8	C_4F_8	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
	In situ thermal cleaning											
$1-U_i$	NA	NA	NA	NA	NA	NA	NA	0.28	NA	NA	NA	NA
BCF_4	NA	NA	NA	NA	NA	NA	NA	0.010	NA	NA	NA	NA
BC_2F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA = Not applicable; i.e., there are no applicable default emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

[78 FR 68221, Nov. 13, 2013]

TABLE I–5 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR MEMS MANUFACTURING

Table I–5 to Subpart I of Part 98—Default Emission Factors (1–U_{ij}) for Gas Utilization Rates (U_{ij}) and By-Product Formation Rates (B_{ijk}) for MEMS Manufacturing

Process type factors	**Process gas i**											
	CF_4	**C_2F_6**	**CHF_3**	**CH_2F_2**	**C_3F_8**	**c-C_4F_8**	**NF_3 Remote**	**NF_3**	**SF_6**	**C_4F_{6a}**	**C_5F_{8a}**	**$C_4F_8O_a$**
* * * * * * *												
CVD Chamber Cleaning 1–U_i	0.9	0.6	NA	NA	0.4	0.1	0.02	0.2	NA	NA	0.1	0.1
CVD Chamber Cleaning BCF_4	NA	0.1	NA	NA	0.1	0.1	[2]0.02	[2]0.1	NA	NA	0.1	0.1
CVD Chamber Cleaning BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.4

Notes: NA = Not applicable; i.e., there are no applicable default emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

[1] Estimate includes multi-gas etch processes.

[2] Estimate reflects presence of low-k, carbide and multi-gas etch processes that may contain a C-containing fluorinated GHG additive.

[75 FR 74818, Dec. 1, 2010, as amended at 78 FR 68225, Nov. 13, 2013]

TABLE I–6 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES(B_{ijk}) FOR LCD MANUFACTURING

Table I–6 to Subpart I of Part 98—Default Emission Factors (1–U_{ij}) for Gas Utilization Rates (U_{ij}) and By-Product Formation Rates (B_{ijk}) for LCD Manufacturing

Process type factors	Process Gas i								
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	$c\text{-}C_4F_8$	NF_3 Remote	NF_3	SF_6
* * * * * * *									
CVD Chamber Cleaning 1–U_i	NA	NA	NA	NA	NA	NA	0.03	0.3	0.9

Notes: NA = Not applicable; i.e., there are no applicable default emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

[75 FR 74818, Dec. 1, 2010, as amended at 78 FR 68225, Nov. 13, 2013]

TABLE I–7 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR PV MANUFACTURING

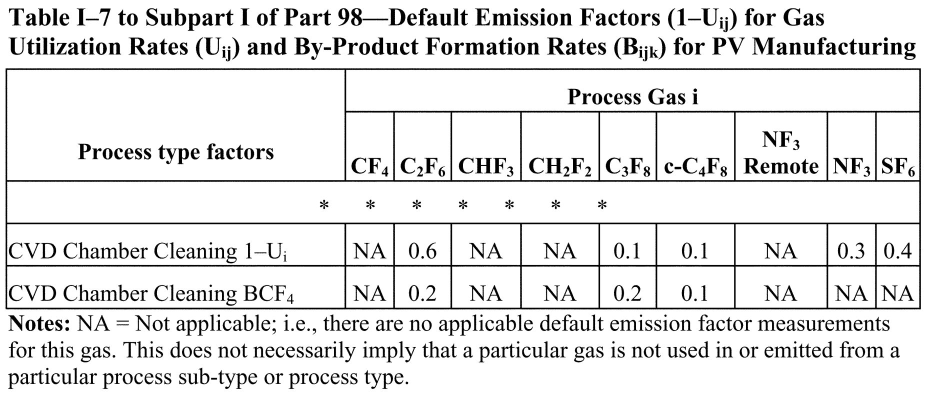

Table I–7 to Subpart I of Part 98—Default Emission Factors (1–U_{ij}) for Gas Utilization Rates (U_{ij}) and By-Product Formation Rates (B_{ijk}) for PV Manufacturing

Process type factors	Process Gas i								
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3 Remote	NF_3	SF_6
* * * * * * *									
CVD Chamber Cleaning 1–U_i	NA	0.6	NA	NA	0.1	0.1	NA	0.3	0.4
CVD Chamber Cleaning BCF_4	NA	0.2	NA	NA	0.2	0.1	NA	NA	NA

Notes: NA = Not applicable; i.e., there are no applicable default emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

[75 FR 74818, Dec. 1, 2010, as amended at 78 FR 68226, Nov. 13, 2013]

TABLE I–8 TO SUBPART I OF PART 98— DEFAULT EMISSION FACTORS (1–$U_{N2O,j}$) FOR N_2O UTILIZATION ($U_{N2O,j}$)

Process type factors	N_2O
CVD 1–U_i	0.8
Other Manufacturing Process 1–U_i	1.0

TABLE I–9 TO SUBPART I OF PART 98—METHODS AND PROCEDURES FOR CONDUCTING EMISSIONS TEST FOR STACK SYSTEMS

Table I-9 to Subpart I of Part 98—Methods and Procedures for Conducting Emissions Tests for Stack Systems

For each stack system for which you use the "stack test method" to calculate annual emissions...	You must...	Using...
For each fluorinated GHG	Measure the concentration in the stack system.	Method 320 at 40 CFR part 63, appendix A or ASTM D6348-03[a] (incorporated by reference, see § 98.7). Conduct the test run for a minimum of 8 hours for each stack system.
	Select sampling port locations and the number of traverse points.	Method 1 or 1A at 40 CFR part 60, appendix A-1.
	Determine gas velocity and volumetric flow rate.	Method 2, 2A, 2C, 2D, 2F, or 2G at 40 CFR part 60, appendix A-1 and A-2.
	Determine gas molecular weight.	Method 3, 3A, or 3B at 40 CFR part 60, appendix A-2 using the same sampling site and time as fluorinated GHG sampling.
	Measure gas moisture content.	Method 4 at 40 CFR part 60, appendix A-3, or using FTIR[b].

[a] Reporters may use ASTM D6348-03 (incorporated by reference, see § 98.7) as an alternative to Method 320 at 40 CFR part 63, appendix A, with the following additional requirements: (1) The test plan preparation and implementation in the Annexes to ASTM D6348-03, Sections A1 through A8 are mandatory; and (2) In ASTM D6348-03 Annex A5 (Analyte Spiking Technique), the percent recovery (%R) must be determined for each target analyte (Equation A5.5). The reporter must also follow Section 4.1 of ASTM D6348-03 to ensure F-GHG remain in the gas phase. In order for the test data to be acceptable for a compound, the percent recovery must be between 70 and 130 percent. If the percent recovery does not meet this criterion for a target compound, the test data are not acceptable for that compound and the test must be repeated for that analyte (i.e., the sampling and/or analytical procedure should be adjusted before a retest). The percent recovery value for each compound must be reported in the test report, required under 40 CFR 98.94(j)(4), and all field measurements must be corrected with the calculated percent recovery value for that compound by using the following equation: Reported Result = Measured Concentration in the stack x (100/% R).

[b] Extractive FTIR is an acceptable method, in lieu of Method 4 at 40 CFR part 60 appendix A, of determining the volumetric concentrations of moisture in semiconductor stack gas streams. The spectral calibrations employed should bracket the anticipated range of optical depths (H_2O concentration in parts per million multiplied by FTIR sample cell path length) measured in the field for moisture saturated (relative humidity approximately 100 percent) air streams at temperatures characterized via Method 2 at 40 CFR part 60 appendix A, within the stack. The HITRAN molecular spectroscopic database is an

example of a widely used international standard of IR absorption parameters that provide accurate H_2O FTIR calibrations at atmospheric conditions. Field measurements should be verified to be in line with moisture saturated wet scrubber exhaust concentrations at measured temperatures. Field measurements at saturated conditions should be verified to be consistent with published water vapor pressure curves at the current stack temperatures (Perry, R.H. and D.W. Green. Perry's Chemical Engineer's Handbook (8th Edition). McGraw-Hill Publishing Company, Inc. New York, New York. 2008). For unsaturated conditions, field measurements should be verified using a single point verification of the FTIR moisture reading using Method 4 at 40 CFR part 60 appendix A, or a NIST traceable hygrometer accurate to +/- 2 percent relative humidity. The FTIR moisture reading shall agree within 10 percent of the moisture measurement obtained using Method 4 at 40 CFR part 60 appendix A or a NIST traceable hygrometer.

[78 FR 68227, Nov. 13, 2013]

TABLE I–10 TO SUBPART I OF PART 98—MAXIMUM FIELD DETECTION LIMITS APPLICABLE TO FLUORINATED GHG CONCENTRATION MEASUREMENTS FOR STACK SYSTEMS

Fluorinated GHG Analyte	Maximum field detection limit (ppbv)
CF_4	20
C_2F_6	20
C_3F_8	20
C_4F_6	20
C_5F_8	20
c–C_4F_8	20
CH_2F_2	40
CH_3F	40
CHF_3	20
NF_3	20
SF_6	4
Other fully fluorinated GHGs	20
Other fluorinated GHGs	40

ppbv—Parts per billion by volume.

[78 FR 68228, Nov. 13, 2013]

TABLE I–11 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR USE WITH THE STACK TEST METHOD (150 MM AND 200 MM WAFERS)

Table I–11 to Subpart I of Part 98–Default Emission Factors (1–U_{ij}) for Gas Utilization Rates (U_{ij}) and By-Product Formation Rates (B_{ijk}) for Semiconductor Manufacturing for use with the Stack Test Method (150 mm and 200 mm wafers)

All Processes	**Process Gas i**													
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_2HF_5	CH_3F	C_3F_8	C_4F_8	NF_3	NF_3 Remote	SF_6	C_4F_6	C_5F_8	C_4F_8O
1-U_i	0.85	0.56	0.50	0.13	0.064	0.51	0.40	0.13	0.16	0.018	0.55	0.17	0.072	0.14
BCF_4	NA	0.19	0.085	0.079	0.077	NA	0.20	0.11	0.045	0.015	0.13	0.13	NA	0.13
BC_2F_6	0.046	NA	0.030	0.025	0.024	0.0034	NA	0.037	0.025	NA	0.11	0.11	0.014	0.045
BC_4F_6	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_4F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_5F_8	0.0012	NA	0.0012	NA	NA	NA	NA	0.0086	NA	NA	NA	NA	NA	NA
$BCHF_3$	0.10	0.047	NA	0.049	NA	NA	NA	0.040	NA	NA	0.0012	0.066	0.0039	NA

Notes: NA = Not applicable; i.e., there are no applicable emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

[78 FR 68229, Nov. 13, 2013]

TABLE I–12 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR SEMICONDUCTOR MANUFACTURING FOR USE WITH THE STACK TEST METHOD (300 MM AND 450 MM WAFERS)

Table I–12 to Subpart I of Part 98–Default Emission Factors (1–U_{ij}) for Gas Utilization Rates (U_{ij}) and By-Product Formation Rates (B_{ijk}) for Semiconductor Manufacturing for use with the Stack Test Method (300 mm and 450 mm Wafer Sizes)

All Processes	Process Gas i												
	CF_4	C_2F_6	CHF_3	CH_2F_2	CH_3F	C_3F_8	C_4F_8	NF_3	NF_3 Remote	SF_6	C_4F_6	C_5F_8	C_4F_8O
1-U_i	0.65	0.80	0.42	0.21	0.33	0.20	0.18	0.20	0.018	0.32	0.15	0.10	NA
BCF_4	NA	0.21	0.095	0.049	0.045	0.21	0.045	0.040	0.075	0.040	0.059	0.11	NA
BC_2F_6	0.079	NA	0.064	0.052	0.00087	0.18	0.031	0.045	NA	0.044	0.074	0.083	NA
BC_4F_6	NA	NA	0.00010	NA	NA	NA	0.018	NA	NA	NA	NA	NA	NA
BC_4F_8	0.00063	NA	0.00080	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	0.00012	NA
BCH_2F_2	NA	NA	0.0036	NA	0.0023	NA	0.0015	0.00086	NA	0.000029	0.000030	NA	NA
BCH_3F	0.0080	NA	0.0080	0.0080	NA	0.00073	NA	0.0080	NA	NA	NA	NA	NA
$BCHF_3$	0.011	NA	NA	0.050	0.0057	0.012	0.027	0.025	NA	0.0037	0.019	0.0069	NA

Notes: NA = Not applicable; i.e., there are no applicable emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

[78 FR 68230, Nov. 13, 2013]

TABLE I–13 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR LCD MANUFACTURING FOR USE WITH THE STACK TEST METHOD

Table I–13 to Subpart I of Part 98—Default Emission Factors (1–U_{ij}) for Gas Utilization Rates (U_{ij}) and By-Product Formation Rates (B_{ijk}) for LCD Manufacturing for use with the Stack Test Method

Process Gas (i)	Process Gas i								
	CF_4	**C_2F_6**	**CHF_3**	**CH_2F_2**	**C_3F_8**	**c-C_4F_8**	**NF_3 Remote**	**NF_3**	**SF_6**
1–U_i	0.6	NA	0.2	NA	NA	0.1	0.03	0.3	0.6
BCF_4	NA	NA	0.07	NA	NA	0.009	NA	NA	NA
$BCHF_3$	NA	NA	NA	NA	NA	0.02	NA	NA	NA
BC_2F_6	NA	NA	0.05	NA	NA	NA	NA	NA	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA = Not applicable; i.e., there are no applicable emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

[78 FR 68231, Nov. 13, 2013]

TABLE I–14 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR PV MANUFACTURING FOR USE WITH THE STACK TEST METHOD

Table I–14 to Subpart I of Part 98—Default Emission Factors (1–U_{ij}) for Gas Utilization Rates (U_{ij}) and By-Product Formation Rates (B_{ijk}) for PV Manufacturing for use with the Stack Test Method

Process Gas (i)	**Process Gas i**								
	CF_4	**C_2F_6**	**CHF_3**	**CH_2F_2**	**C_3F_8**	**c-C_4F_8**	**NF_3 Remote**	**NF_3**	**SF_6**
1–U_i	0.7	0.6	0.4	NA	0.4	0.2	NA	0.2	0.4
BCF_4	NA	0.2	NA	NA	0.2	0.1	NA	0.05	NA
BC_2F_6	NA	NA	NA	NA	NA	0.1	NA	NA	NA
B**C_3F_8**	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA = Not applicable; i.e., there are no applicable emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

[78 FR 68232, Nov. 13, 2013]

TABLE I–15 TO SUBPART I OF PART 98—DEFAULT EMISSION FACTORS (1–U_{ij}) FOR GAS UTILIZATION RATES (U_{ij}) AND BY-PRODUCT FORMATION RATES (B_{ijk}) FOR MEMS MANUFACTURING FOR USE WITH THE STACK TEST METHOD

Table I–15 to Subpart I of Part 98–Default Emission Factors (1–U_{ij}) for Gas Utilization Rates (U_{ij}) and By-Product Formation Rates (B_{ijk}) for MEMS Manufacturing for use with the Stack Test Method

All Processes	Process Gas i											
	CF_4	C_2F_6	CHF_3	CH_2F_2	C_3F_8	c-C_4F_8	NF_3 Remote	NF_3	SF_6	C_4F_6	C_5F_8	C_4F_8O
1-U_i	0.9	0.6	0.4	0.1	0.4	0.1	0.2	0.2	0.2	0.1	0.1	0.1
BCF_4	NA	0.2	0.07	0.08	0.1	0.1	[a]0.02	0.09	NA	0.3	0.1	0.1
BC_2F_6	NA	NA	NA	NA	NA	[a]0.04	NA	NA	NA	0.2	0.04	NA
BC_3F_8	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA

Notes: NA = Not applicable; i.e., there are no applicable emission factor measurements for this gas. This does not necessarily imply that a particular gas is not used in or emitted from a particular process sub-type or process type.

[a] Estimate reflects presence of low-k, carbide and multi-gas etch processes that may contain a C-containing fluorinated GHG additive.

[78 FR 68233, Nov. 13, 2013]

TABLE I–16 TO SUBPART I OF PART 98—DEFAULT EMISSION DESTRUCTION OR REMOVAL EFFICIENCY (DRE) FACTORS FOR ELECTRONICS MANUFACTURING

Manufacturing type/process type/gas	Default DRE (percent)
MEMS, LCDs, and PV Manufacturing	60
Semiconductor Manufacturing:	
Plasma Etch/Wafer Clean Process Type:	
CF_4	75
CH_3F	97
CHF_3	97
CH_2F_2	97
C_2F_6	97
C_3F_8	97
C_4F_6	97
C_4F_8	97
C_5F_8	97
SF_6	97
NF_3	96
All other carbon-based plasma etch/ wafer clean fluorinated GHG	60
Chamber Clean Process Type:	
NF_3	88
All other chamber clean fluorinated GHG	60
N_2O Processes:	
CVD and all other N_2O-using processes	60

[78 FR 68234, Nov. 13, 2013]

TABLE I–17 TO SUBPART I OF PART 98—EXPECTED AND POSSIBLE BY-PRODUCTS FOR ELECTRONICS MANUFACTURINGLG

For each stack system for which you use the "stack test method" to calculate annual emissions, you must measure the following:	If emissions are detected intermittently, use the following procedures:	If emissions are not detected, use the following procedures:
Expected By-products: CF_4 C_2F_6 CHF_3 CH_2F_2 CH_3F	Use the measured concentration for "X_{ksm}" in Equation I–18 when available and use one-half of the field detection limit you determined for the fluorinated GHG according to §98.94(j)(2) for the value of "X_{ksm}" when the fluorinated GHG is not detected.	Use one-half of the field detection limit you determined for the fluorinated GHG according to §98.94(j)(2) for the value of "X_{ksm}" in Equation I–18.
Possible By-products: C_3F_8 C_4F_6 c-C_4F_8 C_5F_8	Use the measured concentration for "X_{ksm}" in Equation I–18 when available and use one-half of the field detection limit you determined for the fluorinated GHG according to §98.94(j)(2) for the value of "X_{ksm}" when the fluorinated GHG is not detected.	Assume zero emissions for that fluorinated GHG for the tested stack system.

[78 FR 68234, Nov. 13, 2013]

APPENDIX A TO SUBPART I OF PART 98—ALTERNATIVE PROCEDURES FOR MEASURING POINT-OF-USE ABATEMENT DEVICE DESTRUCTION OR REMOVAL EFFICIENCY

If you are measuring destruction or removal efficiency of a point-of-use abatement device according to EPA 430–R–10–003 (incorporated by reference, see §98.7) as specified in §98.94(f)(4), you may follow the alternative procedures specified in paragraphs (a) through (c) of this appendix.

(a) In place of the Quadrupole Mass Spectrometry protocol requirements specified in section 2.2.4 of EPA 430–R–10–003 (incorporated by reference, see §98.7), you must conduct mass spectrometry testing in accordance with the provisions in paragraph (a)(1) through (a)(15) of this appendix.

(1) *Detection limits.* The mass spectrometer chosen for this application must have the necessary sensitivity to detect the selected effluent species at or below the maximum field detection limits specified in Table 3 of section 2.2.7 of EPA 430–R–10–003 (incorporated by reference, see §98.7).

(2) *Sampling location.* The sample at the inlet of the point-of-use abatement device must be taken downstream of the process tool and pump package. The sample exhaust must be vented back into the corrosive house ventilation system at a point downstream of the sample inlet location.

(3) *Sampling conditions.* For etch processes, destruction or removal efficiencies must be determined while etching a substrate (product, dummy, or test). For chemical vapor deposition processes, destruction or removal efficiencies must be determined during a chamber clean after deposition (destruction or removal efficiencies must not be determined in a clean chamber). All sampling must be performed non-intrusively during wafer processing. Samples must be drawn through the mass spectrometer source by an

external sample pump. Because of the volatility, vapor pressure, stability and inertness of CF_4, C_2F_6, C_3F_8, CHF_3, NF_3, and SF_6, the sample lines do not need to be heated.

(4) Mass spectrometer parameters. The specific mass spectrometer operating conditions such as electron energy, secondary electron multiplier voltage, emission current, and ion focusing voltage must be selected according to the specifications provided by the mass spectrometer manufacturer, the mass spectrometer system manual, basic mass spectrometer textbook, or other such sources. The mass spectrometer responses to each of the target analytes must all be calibrated under the same mass spectrometer operating conditions.

(5) *Flow rates.* A sample flow rate of 0.5–1.5 standard liters per minute (slm) must be drawn from the process tool exhaust stream under study.

(6) *Sample frequency.* The mass spectrometer sampling frequency for etch processes must be in the range of 0.5 to 1 cycles per second, and for chemical vapor deposition processes must be in the range of 0.25 to 0.5 cycles per second. As an alternative you may use the sampling frequencies specified in section 2.2.4 of EPA 430–R–10–003 (incorporated by reference, see §98.7).

(7) *Dynamic dilution calibration parameters.* The quadrupole mass spectrometer must be calibrated for both mass location and response to analytes. A dynamic dilution calibration system may be used to perform both types of mass spectrometer system calibrations using two mass flow controllers. Use one mass flow controller to regulate the flow rate of the standard component used to calibrate the system and the second mass flow controller to regulate the amount of diluent gas used to mix with the standard to generate the calibration curve for each compound of interest. The mass flow controller must be calibrated using the single component gas being used with them, for example, nitrogen (N_2) for the diluent. A mass flow controller used with calibration mixtures must be calibrated with the calibration mixture balance gas (for example, N_2 or He) if the analyte components are 2 percent or less of the volume of the sample. All calibration mixtures must be National Institute of Standards and Technology Traceable gases or equivalent. They must be calibrated over their range of use and must be operated in their experimentally determined dynamic linear range. If compressed gas standards cannot be brought into the fab, metered gas flows of target compounds into the process chamber, under no thermal or plasma conditions and with no wafer(s) present, and with no process emissions from other tools contributing to the sample location, must then be performed throughout the appropriate concentration ranges to derive calibration curves for the subsequent destruction or removal efficiency tests.

(8) *Mass location calibration.* A mixture containing 1 percent He, Ar, Kr, and Xe in a balance gas of nitrogen must be used to assure the alignment of the quadrupole mass filter (see EPA Method 205 at 40 CFR part 51, appendix M as reference). The mass spectrometer must be chosen so that the mass range is sufficient to detect the predominant peaks of the components under study.

(9) *Quadrupole mass spectrometer response calibration.* A calibration curve must be generated for each compound of interest.

(10) *Calibration frequency.* The mass spectrometer must be calibrated at the start of testing a given process. The calibration must be checked at the end of testing.

(11) *Calibration range.* The mass spectrometer must be calibrated over the expected concentration range of analytes using a minimum of five concentrations including a zero. The zero point is defined as diluent containing no added analyte.

(12) *Operating procedures.* You must follow the operating procedures specified in paragraphs (a)(12)(i) through (v) of this appendix.

(i) You must perform a qualitative mass calibration by running a standard (or by flowing chamber gases under non-process conditions) containing stable components such as Ar, Kr, and Xe that provide predominant signals at m/e values distributed throughout the mass range to be used. You must adjust the quadrupole mass filter as needed to align with the inert gas fragments.

(ii) You must quantitatively calibrate the quadrupole mass spectrometer for each analyte of interest. The analyte concentrations during calibration must include the expected concentrations in the process effluent. The calibration must be performed under the same operating conditions, such as inlet pressure, as when sampling process exhaust. If the calibration inlet pressure differs from the sampling inlet pressure then the relationship between inlet pressure and quadrupole mass spectrometer signal response must be empirically determined and applied to correct for any differences between calibration and process emissions monitoring data.

(iii) To determine the response time of the instrument to changes in a process, a process gas such as C_2F_6 must be turned on at the process tool for a fixed period of time (for example, 20 seconds), after which the gas is shut off. The sample flow rate through the system must be adjusted so that the signal increases to a constant concentration within a few seconds and decreases to background levels also within a few seconds.

(iv) You must sample the process effluent through the quadrupole mass spectrometer and acquire data for the required amount of time to track the process, as determined in paragraph (a)(12)(iii) of this appendix. You must set the sample frequency to monitor the changes in the process as specified in paragraph (a)(6) of this appendix. You must repeat this for at least five substrates on the same process and calculate the average and standard deviation of the analyte concentration.

(v) You must repeat the quantitative calibration at the conclusion of sampling to identify any drifts in quadrupole mass spectrometer sensitivity. If drift is observed, you must use an internal standard to correct for changes in sensitivity.

(13) *Sample analysis.* To determine the concentration of a specific component in the sample, you must divide the ion intensity of the sample response by the calibrated response factor for each component.

(14) *Deconvolution of interfering peaks.* The effects of interfering peaks must be deconvoluted from the mass spectra for each target analyte.

(15) *Calculations.* Plot ion intensity versus analyte concentration for a given compound obtained when calibrating the analytical system. Determine the slope and intercept for each calibrated species to obtain response factors with which to calculate concentrations in the sample. For an acceptable calibration, the R^2 value of the calibration curve must be at least 0.98.

(b) In place of the Fourier Transform Infrared Spectroscopy protocol requirements specified in section 2.2.4 of EPA 430–R–10–003 (incorporated by reference, see §98.7), you may conduct Fourier Transform Infrared Spectroscopy testing in accordance with the provisions in paragraph (b)(1) through (17) of this appendix, including the laboratory study phase described in paragraphs (b)(1) through (7), and the field study phase described in paragraphs (b)(8) through (17) of this appendix.

(1) *Conformance with provisions associated with the Calibration Transfer Standard.* This procedure calls for the use of a calibration transfer standard in a number of instances. The use of a calibration transfer standard is necessary to validate optical pathlength and detector response for spectrometers where cell temperature, cell pressure, and cell optical pathlength are potentially variable. For fixed pathlength spectrometers capable of controlling cell temperature and pressure to within ± 10 percent of a desired set point, the use of a calibration transfer standard, as described in paragraphs (b)(2) to (17) this appendix is not required.

(2) *Defining spectroscopic conditions.* Define a set of spectroscopic conditions under which the field studies and subsequent field applications are to be carried out. These include the minimum instrumental line-width, spectrometer wave number range, sample gas temperature, sample gas pressure, absorption pathlength, maximum sampling system volume (including the absorption cell), minimum sample flow rate, and maximum allowable time between consecutive infrared analyses of the effluent.

(3) *Criteria for reference spectral libraries.* On the basis of previous emissions test results and/or process knowledge (including the documentation of results of any initial and subsequent tests, and the final reports required in §98.97(d)(4)(i)), estimate the maximum concentrations of all of the analytes in the effluent and their minimum concentrations of interest (those concentrations below which the measurement of the compounds is of no importance to the analysis). Values between the maximum expected concentration and the minimum concentration of interest are referred to below as the ''expected concentration range.'' A minimum of three reference spectra is sufficient for a small expected concentration range (e.g., a difference of 30 percent of the range between the low and high ends of the range), but a minimum of four spectra are needed where the range is greater, especially for concentration ranges that may differ by orders of magnitude. If the measurement method is not linear then multiple linear ranges may be necessary. If this approach is adopted, then linear range must be demonstrated to pass the required quality control. When the set of spectra is ordered according to absorbance, the absorbance levels of adjacent reference spectra should not differ by more than a factor of six. Reference spectra for each analyte should be available at absorbance levels that bracket the analyte's expected concentration range; minimally, the spectrum whose absorbance exceeds each analyte's expected maximum concentration or is within 30 percent of it must be available. The reference spectra must be collected at or near the same temperature and pressure at which the sample is to be analyzed under. The gas sample pressure and temperature must be continuously monitored during field testing and you must correct for differences in temperature and pressure between the sample and reference spectra. Differences between the sample and reference spectra conditions must not exceed 50 percent for pressure and 40 °C for temperature.

(4) *Spectra without reference libraries.* If reference spectral libraries meeting the criteria in paragraph (b)(3) of this appendix do not exist for all the analytes and interferants or cannot be accurately generated from existing libraries exhibiting lower minimum instrumental line-width values than those proposed for the testing, prepare the required spectra according to the procedures specified in paragraphs (b)(4)(i) and (ii) of this appendix.

(i) Reference spectra at the same absorbance level (to within 10 percent) of independently prepared samples must be recorded. The reference samples must be prepared from neat forms of the analyte or from gas standards of the highest quality commonly available from commercial sources. Either barometric or volumetric methods may be used to dilute the reference samples to the required concentrations, and the equipment used must be independently calibrated to ensure suitable accuracy. Dynamic and static reference sample preparation methods are acceptable, but dynamic preparations must be used for reactive analytes. Any well characterized absorption pathlength may be employed in recording reference spectra, but the temperature and pressure of the reference samples should match as closely as possible those of the proposed spectroscopic conditions.

(ii) If a mercury cadmium telluride or other potentially non-linear detector (i.e., a detector whose response vs. total infrared power is not a linear function over the range of responses employed) is used for recording the reference spectra, you must correct for the effects of this type of response on the resulting concentration values. As needed, spectra of a calibration transfer standard must be recorded with the laboratory spectrometer system to verify the absorption pathlength and other aspects of the system performance. All reference spectral data must be recorded in interferometric form and stored digitally.

(5) *Sampling system preparation.* Construct a sampling system suitable for delivering the proposed sample flow rate from the effluent source to the infrared absorption cell. For the compounds of interest, the surfaces of the system exposed to the effluent stream may need to be stainless steel or Teflon; because of the potential for generation of inorganic automated gases, glass surfaces within the sampling system and absorption cell may need to be Teflon-coated. The sampling system should be able to deliver a volume of sample that results in a necessary response time.

(6) *Preliminary analytical routines.* For the proposed absorption pathlength to be used in actual emissions testing, you must prepare an analysis method containing of all the effluent compounds at their expected maximum concentrations plus the field calibration transfer standard compound at 20 percent of its full concentration as needed.

(7) *Documentation.* The laboratory techniques used to generate reference spectra and to convert sample spectral information to compound concentrations must be documented. The required level of detail for the documentation is that which allows an independent analyst to reproduce the results from the documentation and the stored interferometric data.

(8) *Spectroscopic system performance.* The performance of the proposed spectroscopic system, sampling system, and analytical method must be rigorously examined during and after a field study. Several iterations of the analysis method may need to be applied depending on observed concentrations, absorbance intensities, and interferences. During the field study, all the sampling and analytical procedures envisioned for future field applications must be documented. Additional procedures not required during routine field applications, notably dynamic spiking studies of the analyte gases, may be performed during the field study. These additional procedures need to be performed only once if the results are acceptable and if the effluent sources in future field applications prove suitably similar to those chosen for the field study. If changes in the effluent sources in future applications are noted and require substantial changes to the analytical equipment and/or conditions, a separate field study must be performed for the new set of effluent source conditions. All data recorded during the study must be retained and documented, and all spectral information must be permanently stored in interferometric form.

(9) *System installation.* The spectroscopic and sampling sub-systems must be assembled and installed according to the manufacturers' recommendations. For the field study, the length of the sample lines used must not be less than the maximum length envisioned for future field applications. The system must be given sufficient time to stabilize before testing begins.

(10) *Pre-Test calibration.* Record a suitable background spectrum using pure nitrogen gas; alternatively, if the analytes of interest are in a sample matrix consistent with ambient air, it is beneficial to use an ambient air background to control interferences from water and carbon dioxide. For variable pathlength Fourier Transform Infrared Spectrometers, introduce a sample of the calibration transfer standard gas directly into the absorption cell at the expected sample pressure and record its absorbance spectrum (the ''initial field calibration transfer standard spectrum''). Compare it to the laboratory calibration transfer standard spectra to determine the effective absorption pathlength. If possible, record spectra of field calibration gas standards (single component standards of the analyte compounds) and determine their concentrations using the reference spectra and analytical routines developed in paragraphs (b)(2) through (7) of this appendix; these spectra may be used instead of the reference spectra in actual concentration and uncertainty calculations.

(11) *Deriving the calibration transfer standard gas from tool chamber gases.* The calibration transfer standard gas may be derived by flowing appropriate semiconductor tool chamber gases under non-process conditions (no thermal or plasma conditions and with no wafer(s) present) if compressed gas standards cannot be brought on-site.

(12) *Reactivity and response time checks.* While sampling ambient air and continuously recording absorbance spectra, suddenly replace the ambient air flow with calibration transfer standard gas introduced as close as possible to the probe tip. Examine the subsequent spectra to determine whether the flow rate and sample volume allow the system to respond quickly enough to changes in the sampled gas. Should a corrosive or reactive gas be of interest in the sample matrix it would be beneficial to determine the reactivity in a similar fashion, if practical. Examine the subsequent spectra to ensure that the reactivities of the analytes with the exposed surfaces of the sampling system do not limit the time response of the analytical system. If a pressure correction routine is not automated, monitor the absorption cell temperature and pressure; verify that the (absolute) pressure remains within 2 percent of the pressure specified in the proposed system conditions.

(13) *Analyte spiking.* Analyte spiking must be performed. While sampling actual source effluent, introduce a known flow rate of calibration transfer standard gas into the sample stream as close as possible to the probe tip or between the probe and extraction line. Measure and monitor the total sample flow rate, and adjust the spike flow rate until it represents 10 percent to 20 percent of the total flow rate. After waiting until at least four absorption cell volumes have been sampled, record four spectra of the spiked effluent, terminate the calibration transfer standard spike flow, pause until at least four cell volumes are sampled, and then record four (unspiked) spectra. Repeat this process until 12 spiked and 12 unspiked spectra have been obtained. If a pressure correction routine is not automated, monitor the absorption cell temperature and pressure; verify that the pressure remains within 2 percent of the pressure specified in the proposed system conditions. Calculate the expected calibration transfer standard compound concentrations in the spectra and compare them to the values observed in the spectrum. This procedure is best performed using a spectroscopic tracer to calculate dilution (as opposed to measured flow rates) of the injected calibration transfer standard (or analyte). The spectroscopic tracer should be a component not in the gas matrix that is easily detectable and maintains a linear absorbance over a large concentration range. Repeat this spiking process with all effluent compounds that are potentially reactive with either the sampling system components or with other effluent compounds. The gas spike is delivered by a mass flow controller, and the expected concentration of analyte of interest (AOITheoretical) is calculated as follows:

$$AOI_{Theoretical} = \left(\frac{Tracer_{sample}}{Tracer_{cylinder}}\right)\left(AOI_{cylinder}\right) + \left[1 - \left(\frac{Tracer_{sample}}{Tracer_{cylinder}}\right)\right]\left(AOI_{native}\right)$$

Where:

AOITheoretical = Theoretical analyte of interest concentration (parts per million (ppm)).

Tracersample = Tracer concentration (ppm) as seen by the Fourier Transform Infrared Spectrometer during spiking.

Tracercylinder = The concentration (ppm) of tracer recorded during direct injection of the cylinder to the Fourier Transform Infrared Spectrometer cell.

AOIcylinder = The supplier-certified concentration (ppm) of the analyte of interest gas standard.

AOInative = The native AOI concentration (ppm) of the effluent during stable conditions.

(14) *Post-test calibration.* At the end of a sampling run and at the end of the field study, record the spectrum of the calibration transfer standard gas. The resulting "final field calibration transfer standard spectrum" must be compared to the initial field calibration transfer standard spectrum to verify suitable stability of the spectroscopic system throughout the course of the field study.

(15) *Amendment of analytical routines.* The presence of unanticipated interferant compounds and/or the observation of compounds at concentrations outside their expected concentration ranges may necessitate the repetition of portions of the procedures in paragraphs (b)(2) through (14) of this appendix. Such amendments are allowable before final analysis of the data, but must be represented in the documentation required in paragraph (b)(16) of this appendix.

(16) *Documentation.* The sampling and spiking techniques used to generate the field study spectra and to convert

sample spectral information to concentrations must be documented at a level of detail that allows an independent analyst to reproduce the results from the documentation and the stored interferometric data.

(17) *Method application.* When the required laboratory and field studies have been completed and if the results indicate a suitable degree of accuracy, the methods developed may be applied to practical field measurement tasks. During field applications, the procedures demonstrated in the field study specified in paragraphs (b)(8) through (16) of this appendix must be adhered to as closely as possible, with the following exceptions specified in paragraphs (b)(17)(i) through (iii) of this appendix:

(i) The sampling lines employed should be as short as practically possible and not longer than those used in the field study.

(ii) Analyte spiking and reactivity checks are required after the installation of or major repair to the sampling system or major change in sample matrix. In these cases, perform three spiked/unspiked samples with calibration transfer standard or a surrogate analyte on a daily basis if time permits and gas standards are easy to obtain and get on-site.

(iii) Sampling and other operational data must be recorded and documented as during the field study, but only the interferometric data needed to sufficiently reproduce actual test and spiking data must be stored permanently. The format of this data does not need to be interferograms but may be absorbance spectra or single beams.

(c) When using the flow and dilution measurement protocol specified in section 2.2.6 of EPA 430–R–10–003 (incorporated by reference, see §98.7), you may determine point-of-use abatement device total volume flow with the modifications specified in paragraphs (c)(1) through (3) of this appendix.

(1) You may introduce the non-reactive, non-native gas used for determining total volume flow and dilution across the point-of-use abatement device at a location in the exhaust of the point-of-use abatement device. For abatement systems operating in a mode where specific F–GHG are not readily abated, you may introduce the non-reactive, non-native gas used for determining total volume flow and dilution across the point-of-use abatement device prior to the point-of-use abatement system; in this case, the tracer must be more difficult to destroy than the target compounds being measured based on the thermal stability of the tracer and target.

(2) You may select a location for downstream non-reactive, non-native gas analysis that complies with the requirements in this paragraph (c)(2) of this appendix. The sampling location should be traversed with the sampling probe measuring the non-reactive, non-native gas concentrations to ensure homogeneity of the non-reactive gas and point-of-use abatement device effluent (i.e., stratification test). To test for stratification, measure the non-reactive, non-native gas concentrations at three points on a line passing through the centroidal area. Space the three points at 16.7, 50.0, and 83.3 percent of the measurement line. Sample for a minimum of twice the system response time, determined according to paragraph (c)(3) of this appendix, at each traverse point. Calculate the individual point and mean non-reactive, non-native gas concentrations. If the non-reactive, non-native gas concentration at each traverse point differs from the mean concentration for all traverse points by no more than ±5.0 percent of the mean concentration, the gas stream is considered unstratified and you may collect samples from a single point that most closely matches the mean. If the 5.0 percent criterion is not met, but the concentration at each traverse point differs from the mean concentration for all traverse points by no more than ±10.0 percent of the mean, you may take samples from two points and use the average of the two measurements. Space the two points at 16.7, 50.0, or 83.3 percent of the measurement line. If the concentration at each traverse point differs from the mean concentration for all traverse points by more than ±10.0 percent of the mean but less than 20.0 percent, take samples from three points at 16.7, 50.0, and 83.3 percent of the measurement line and use the average of the three measurements. If the gas stream is found to be

stratified because the 20.0 percent criterion for a 3-point test is not met, locate and sample the non-reactive, nonnative gas from traverse points for the test in accordance with Sections 11.2 and 11.3 of EPA Method 1 in 40 CFR part 60, Appendix A–1. A minimum of 40 non-reactive gas concentration measurements will be collected at three to five different injected non-reactive gas flow rates for determination of point-of-use abatement device effluent flow. The total volume flow of the point-of-use abatement device exhaust will be calculated consistent with the EPA 430–R–10–003 (incorporated by reference, see § 98.7) Equations 1 through 7.

(3) You must determine the measurement system response time according to paragraphs (c)(3)(i) through (iii) of this appendix.

(i) Before sampling begins, introduce ambient air at the probe upstream of all sample condition components in system calibration mode. Record the time it takes for the measured concentration of a selected compound (for example, carbon dioxide) to reach steady state.

(ii) Introduce nitrogen in the system calibration mode and record the time required for the concentration of the selected compound to reach steady state.

(iii) Observe the time required to achieve 95 percent of a stable response for both nitrogen and ambient air. The longer interval is the measurement system response time.

[78 FR 68234, Nov. 13, 2013]

Subpart J [Reserved]

Subpart K—Ferroalloy Production

§ 98.110 Definition of the source category.

The ferroalloy production source category consists of any facility that uses pyrometallurgical techniques to produce any of the following metals: ferrochromium, ferromanganese, ferromolybdenum, ferronickel, ferrosilicon, ferrotitanium, ferrotungsten, ferrovanadium, silicomanganese, or silicon metal.

§ 98.111 Reporting threshold.

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

§ 98.112 GHGs to report.

You must report:

(a) Process CO_2 emissions from each electric arc furnace (EAF) used for the production of any ferroalloy listed in § 98.110, and process CH_4 emissions from each EAF that is used for the production of any ferroalloy listed in Table K–1 to subpart K.

(b) CO_2, CH_4, and N_2O emissions from each stationary combustion unit following the requirements of subpart C of this part. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66461, Oct. 28, 2010]

§ 98.113 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each EAF not subject to paragraph (c) of this section using the procedures in either paragraph (a) or (b) of this section. For each EAF also subject to annual process CH_4 emissions reporting, you must also calculate and report the annual process CH_4 emissions from the EAF using the procedures in paragraph (d) of this section.

(a) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the annual process CO_2 emissions using the procedure in either paragraph (b)(1) or (b)(2) of this section.

(1) Calculate and report under this subpart the annual process CO_2 emissions from EAFs by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology specified in § 98.33(a)(4) and the applicable requirements for Tier 4 in subpart C of

this part (General Stationary Fuel Combustion Sources).

(2) Calculate and report under this subpart the annual process CO_2 emissions from the EAFs using the carbon mass balance procedure specified in paragraphs (b)(2)(i) and (b)(2)(ii) of this section.

(i) For each EAF, determine the an nual mass of carbon in each carbon-containing input and output material for the EAF and estimate annual process CO_2 emissions from the EAF using Equation K–1 of this section. Carbon-containing input materials include carbon electrodes and carbonaceous reducing agents. If you document that a specific input or output material contributes less than 1 percent of the total carbon into or out of the process, you do not have to include the material in your calculation using Equation K–1 of this section.

$$
\begin{aligned}
E_{CO2} = {} & \frac{44}{12} \times \frac{2000}{2205} \times \sum_{1}^{i} \left(M_{reducing\ agent_i} \times C_{reducing\ agent_i} \right) \\
& + \frac{44}{12} \times \frac{2000}{2205} \times \sum_{1}^{m} \left(M_{electrode_m} \times C_{electrode_m} \right) \\
& + \frac{44}{12} \times \frac{2000}{2205} \times \sum_{1}^{h} \left(M_{ore_h} \times C_{ore_h} \right) \qquad \text{(Eq. K-1)} \\
& + \frac{44}{12} \times \frac{2000}{2205} \times \sum_{1}^{j} \left(M_{\mathrm{flux}_\mathrm{j}} \times \mathrm{C}_{\mathrm{flux}_\mathrm{j}} \right) \\
& - \frac{44}{12} \times \frac{2000}{2205} \times \sum_{1}^{k} \left(M_{product\ outgoing_k} \times C_{product\ outgoing_k} \right) \\
& - \frac{44}{12} \times \frac{2000}{2205} \times \sum_{1}^{l} \left(M_{non\text{-}product\ outgoing_l} \times C_{non\text{-}product\ outgoing_l} \right)
\end{aligned}
$$

Where:

E_{CO2} = Annual process CO_2 emissions from an individual EAF (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

2000/2205 = Conversion factor to convert tons to metric tons.

$M_{reducing\ agent_i}$ = Annual mass of reducing agent *i* fed, charged, or otherwise introduced into the EAF (tons).

$C_{reducing\ agent_i}$ = Carbon content in reducing agent *i* (percent by weight, expressed as a decimal fraction).

$M_{electrode_m}$ = Annual mass of carbon electrode *m* consumed in the EAF (tons).

$C_{electrode_m}$ = Carbon content of the carbon electrode *m* (percent by weight, expressed as a decimal fraction).

M_{ore_h} = Annual mass of ore *h* charged to the EAF (tons).

C_{ore_h} = Carbon content in ore *h* (percent by weight, expressed as a decimal fraction).

M_{flux_j} = Annual mass of flux material *j* fed, charged, or otherwise introduced into the EAF to facilitate slag formation (tons).

C_{flux_j} = Carbon content in flux material *j* (percent by weight, expressed as a decimal fraction).

$M_{product_k}$ = Annual mass of alloy product *k* tapped from EAF (tons).

$C_{product_k}$ = Carbon content in alloy product *k*. (percent by weight, expressed as a decimal fraction).

$M_{non\text{-}product\ outgoing_l}$ = Annual mass of non-product outgoing material *l* removed from EAF (tons).

$C_{non\text{-}product\ outgoing_l}$ = Carbon content in non-product outgoing material *l* (percent by weight, expressed as a decimal fraction).

(ii) Determine the combined annual process CO_2 emissions from the EAFs at your facility using Equation K–2 of this section.

$$CO_2 = \sum_{1}^{k} E_{CO2_k} \qquad \text{(Eq. K-2)}$$

Where:

CO_2 = Annual process CO_2 emissions from EAFs at facility used for the production of any ferroalloy listed in § 98.110 (metric tons).

E_{CO2_k} = Annual process CO_2 emissions calculated from EAF *k* calculated using Equation K–1 of this section (metric tons).

k = Total number of EAFs at facility used for the production of any ferroalloy listed in § 98.110.

(c) If GHG emissions from an EAF are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

(d) For the EAFs at your facility used for the production of any ferroalloy listed in Table K–1 of this subpart, you must calculate and report the annual CH_4 emissions using the procedure specified in paragraphs (d)(1) and (2) of this section.

(1) For each EAF, determine the annual CH_4 emissions using Equation K–3 of this section.

$$E_{CH_4} = \sum_{1}^{i} \left(M_{product_i} \times \frac{2}{2205} \times EF_{product_i}\right) \qquad \text{(Eq. K-3)}$$

Where:

E_{CH4} = Annual process CH_4 emissions from an individual EAF (metric tons).

$M_{product_i}$ = Annual mass of alloy product *i* produced in the EAF (tons).

2/2205 = Conversion factor to convert kg CH_4/ton of product to metric tons CH_4.

$EF_{product_i}$ = CH_4 emission factor for alloy product *i* from Table K–1 in this subpart (kg of CH_4 emissions per metric ton of alloy product *i*).

(2) Determine the combined process CH_4 emissions from the EAFs at your facility using Equation K–4 of this section:

$$CH_4 = \sum_{1}^{j} E_{CH4_j} \qquad \text{(Eq. K-4)}$$

Where:

CH_4 = Annual process CH_4 emissions from EAFs at facility used for the production of ferroalloys listed in Table K–1 of this subpart (metric tons).

E_{CH4_j} = Annual process CH_4 emissions from EAF *j* calculated using Equation K–3 of this section (metric tons).

j = Total number of EAFs at facility used for the production of ferroalloys listed in Table K–1 of this subpart.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66461, Oct. 28, 2010; 78 FR 71954, Nov. 29, 2013]

§ 98.114 Monitoring and QA/QC requirements.

If you determine annual process CO_2 emissions using the carbon mass balance procedure in § 98.113(b)(2), you must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) Determine the annual mass for each material used for the calculations of annual process CO_2 emissions using Equation K–1 of this subpart by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

(b) For each material identified in paragraph (a) of this section, you must determine the average carbon content of the material consumed, used, or produced in the calendar year using the methods specified in either paragraph (b)(1) or (b)(2) of this section. If you document that a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(1) Information provided by your material supplier.

(2) Collecting and analyzing at least three representative samples of the material inputs and outputs each year. The carbon content of the material must be analyzed at least annually using the standard methods (and their QA/QC procedures) specified in paragraphs (b)(2)(i) through (b)(2)(iii) of this section, as applicable.

(i) ASTM E1941–04, Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys (incorporated by reference, *see* §98.7) for analysis of metal ore and alloy product.

(ii) 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), for analysis of carbonaceous reducing agents and carbon electrodes.

(iii) ASTM C25–06, Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference, *see* §98.7) for analysis of flux materials such as limestone or dolomite.

§98.115 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in §98.113 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) If you determine CO_2 emissions for the EAFs at your facility using the carbon mass balance procedure in §98.113(b), 100 percent data availability is required for the carbon content of the input and output materials. You must repeat the test for average carbon contents of inputs according to the procedures in §98.114(b) if data are missing.

(b) For missing records of the monthly mass of carbon-containing inputs and outputs, the substitute data value must be based on the best available estimate of the mass of the inputs and outputs from on all available process data or data used for accounting purposes, such as purchase records.

(c) If you are required to calculate CH_4 emissions for an EAF at your facility as specified in §98.113(d), the estimate is based an annual quantity of certain alloy products, so 100 percent data availability is required.

§98.116 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (e) of this section, as applicable:

(a) Annual facility ferroalloy product production capacity (tons).

(b) Annual production for each ferroalloy product identified in §98.110, from each EAF (tons).

(c) Total number of EAFs at facility used for production of ferroalloy products.

(d) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required by §98.36 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (d)(1) through (d)(3) of this section.

(1) Annual process CO_2 emissions (in metric tons) from each EAF used for the production of any ferroalloy product identified in §98.110.

(2) Annual process CH_4 emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K–1 of this subpart (metric tons).

(3) Identification number of each EAF.

(e) If a CEMS is not used to measure CO_2 process emissions, and the carbon mass balance procedure is used to determine CO_2 emissions according to the requirements in § 98.113(b), then you must report the following information specified in paragraphs (e)(1) through (e)(7) of this section.

(1) Annual process CO_2 emissions (in metric tons) from each EAF used for the production of any ferroalloy identified in § 98.110 (metric tons).

(2) Annual process CH_4 emissions (in metric tons) from each EAF used for the production of any ferroalloy listed in Table K–1 of this subpart.

(3) Identification number for each material.

(4) Annual material quantity for each material included for the calculation of annual process CO_2 emissions for each EAF.

(5) Annual average of the carbon content determinations for each material included for the calculation of annual process CO_2 emissions for each EAF (percent by weight, expressed as a decimal fraction).

(6) List the method used for the determination of carbon content for each material reported in paragraph (e)(5) of this section (e.g., supplier provided information, analyses of representative samples you collected).

(7) If you use the missing data procedures in § 98.115(b), you must report how monthly mass of carbon-containing inputs and outputs with missing data was determined and the number of months the missing data procedures were used.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66462, Oct. 28, 2010; 78 FR 71954, Nov. 29, 2013]

§ 98.117 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (d) of this section for each EAF, as applicable.

(a) If a CEMS is used to measure CO_2 emissions according to the requirements in § 98.113(a), then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37 and the information specified in paragraphs (a)(1) through (a)(3) of this section.

(1) Monthly EAF production quantity for each ferroalloy product (tons).

(2) Number of EAF operating hours each month.

(3) Number of EAF operating hours in a calendar year.

(b) If the carbon mass balance procedure is used to determine CO_2 emissions according to the requirements in § 98.113(b)(2), then you must retain records for the information specified in paragraphs (b)(1) through (b)(5) of this section.

(1) Monthly EAF production quantity for each ferroalloy product (tons).

(2) Number of EAF operating hours each month.

(3) Number of EAF operating hours in a calendar year.

(4) Monthly material quantity consumed, used, or produced for each material included for the calculations of annual process CO_2 emissions (tons).

(5) Average carbon content determined and records of the supplier provided information or analyses used for the determination for each material included for the calculations of annual process CO_2 emissions.

(c) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input and output to each EAF, including documentation of specific input or output materials excluded from Equation K–1 of this subpart that contribute less than 1 percent of the total carbon into or out of the process. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in an EAF including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(d) If you are required to calculate CH_4 emissions for the EAF as specified in § 98.113(d), you must maintain records of the total amount of each alloy product produced for the specified reporting period, and the appropriate alloy-product specific emission factor used to calculate the CH_4 emissions.

§98.118 Definitions.

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

TABLE K–1 TO SUBPART K OF PART 98—ELECTRIC ARC FURNACE (EAF) CH_4 EMISSION FACTORS

Alloy product produced in EAF	CH_4 emission factor (kg CH_4 per metric ton product)		
	EAF Operation		
	Batch-charging	Sprinkle-charging [a]	Sprinkle-charging and >750 °C [b]
Silicon metal	1.5	1.2	0.7
Ferrosilicon 90%	1.4	1.1	0.6
Ferrosilicon 75%	1.3	1.0	0.5
Ferrosilicon 65%	1.3	1.0	0.5

[a] Sprinkle-charging is charging intermittently every minute.

[b] Temperature measured in off-gas channel downstream of the furnace hood.

Subpart L—Fluorinated Gas Production

SOURCE: 75 FR 74831, Dec. 1, 2010, unless otherwise noted.

§98.120 Definition of the source category.

(a) The fluorinated gas production source category consists of processes that produce a fluorinated gas from any raw material or feedstock chemical, except for processes that generate HFC–23 during the production of HCFC–22.

(b) To produce a fluorinated gas means to manufacture a fluorinated gas from any raw material or feedstock chemical. Producing a fluorinated gas includes producing a fluorinated GHG as defined at §98.410(b). Producing a fluorinated gas also includes the manufacture of a chlorofluorocarbon (CFC) or hydrochlorofluorocarbon (HCFC) from any raw material or feedstock chemical, including manufacture of a CFC or HCFC as an isolated intermediate for use in a process that will result in the transformation of the CFC or HCFC either at or outside of the production facility. Producing a fluorinated gas does not include the reuse or recycling of a fluorinated gas, the creation of HFC–23 during the production of HCFC–22, the creation of intermediates that are created and transformed in a single process with no storage of the intermediates, or the creation of fluorinated GHGs that are released or destroyed at the production facility before the production measurement in §98.414(a).

§98.121 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a fluorinated gas production process that generates or emits fluorinated GHG and the facility meets the requirements of either §98.2(a)(1) or (a)(2). To calculate GHG emissions for comparison to the 25,000 metric ton CO_2e per year emission threshold in §98.2(a)(2), calculate process emissions from fluorinated gas production using uncontrolled GHG emissions.

§98.122 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O combustion emissions from each stationary combustion unit. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(b) You must report under subpart O of this part (HCFC–22 Production and HFC–23 Destruction) the emissions of HFC–23 from HCFC–22 production processes and HFC–23 destruction processes. Do not report the generation and emissions of HFC–23 from HCFC–22 production under this subpart.

(c) You must report the total mass of each fluorinated GHG emitted from:

(1) Each fluorinated gas production process and all fluorinated gas production processes combined.

(2) Each fluorinated gas transformation process that is not part of a fluorinated gas production process and all such fluorinated gas transformation processes combined, except report separately fluorinated GHG emissions from transformation processes where a fluorinated GHG reactant is produced at another facility.

(3) Each fluorinated gas destruction process that is not part of a fluorinated gas production process or a fluorinated gas transformation process and all such fluorinated gas destruction processes combined.

(4) Venting of residual fluorinated GHGs from containers returned from the field.

§ 98.123 Calculating GHG emissions.

For fluorinated gas production and transformation processes, you must calculate the fluorinated GHG emissions from each process using either the mass balance method specified in paragraph (b) of this section or the emission factor or emission calculation factor method specified in paragraphs (c), (d), and (e) of this section, as appropriate. For destruction processes that destroy fluorinated GHGs that were previously ‘‘produced’’ as defined at § 98.410(b), you must calculate emissions using the procedures in paragraph (f) of this section. For venting of residual gas from containers (e.g., cylinder heels), you must calculate emissions using the procedures in paragraph (g) of this section.

(a) *Default GWP value.* In paragraphs (b)(1) and (c)(1) of this section and in § 98.124(b)(8) and (c)(2), use a GWP of 2,000 for fluorinated GHGs that do not have GWPs listed in Table A–1 to subpart A of this part, except as provided in paragraph § 98.123(c)(1)(vi). Do not report CO_2e emissions under § 98.3(c)(4) for fluorinated GHGs that do not have GWPs listed in Table A–1 to subpart A of this part.

(b) *Mass balance method.* Before using the mass balance approach to estimate your fluorinated GHG emissions from a process, you must ensure that the process and the equipment and methods used to measure it meet either the error limits described in this paragraph and calculated under paragraph (b)(1) of this section or the requirements specified in paragraph § 98.124(b)(8). If you choose to calculate the error limits, you must estimate the absolute and relative errors associated with using the mass balance approach on that process using Equations L–1 through L–4 of this section in conjunction with Equations L–5 through L–10 of this section. You may use the mass-balance approach to estimate emissions from the process if this calculation results in an absolute error of less than or equal to 3,000 metric tons CO_2e per year or a relative error of less than or equal to 30 percent of the estimated CO_2e fluorinated GHG emissions. If you do not meet either of the error limits or the requirements of paragraph § 98.124(b)(8), you must use the emission factor approach detailed in paragraphs (c), (d), and (e) of this section to estimate emissions from the process.

(1) *Error calculation.* To perform the calculation, you must first calculate the absolute and relative errors associated with the quantities calculated using either Equations L–7 through L–10 of this section or Equation L–17 of this section. Alternatively, you may estimate these errors based on the variability of previous process measurements (e.g., the variability of measurements of stream concentrations), provided these measurements are representative of the current process and current measurement devices and techniques. Once errors have been calculated for the quantities in these equations, those errors must be used to calculate the errors in Equations L–6 and L–5 of this section. You may ignore the errors associated with Equations L–11, L–12, and L–13 of this section.

(i) Where the measured quantity is a mass, the error in the mass must be equated to the accuracy or precision (whichever is larger) of the flowmeter, scale, or combination of volumetric and density measurements at the flow rate or mass measured.

(ii) Where the measured quantity is a concentration of a stream component, the error of the concentration must be equated to the accuracy or precision (whichever is larger) with which you estimate the mean concentration of that stream component, accounting for the variability of the process, the frequency of the measurements, and the accuracy or precision (whichever is larger) of the analytical technique used to measure the concentration at the concentration measured. If the variability of process measurements is used to estimate the error, this variability shall be assumed to account both for the variability of the process and the precision of the analytical technique. Use standard statistical techniques such as the student's t distribution to estimate the error of the mean of the concentration measurements as a function of process variability and frequency of measurement.

(iii) Equation L–1 of this section provides the general formula for calculating the absolute errors of sums and differences where the sum, S, is the summation of variables measured, a, b, c, etc. (e.g., S = a + b + c):

$$e_{SA} = [(a*e_a)^2 + (b*e_b)^2 + (c*e_c)^2]^{1/2} \quad \text{(Eq. L-1)}$$

where:

e_{SA} = Absolute error of the sum, expressed as one half of a 95 percent confidence interval.

e_a = Relative error of a, expressed as one half of a 95 percent confidence interval.

e_b = Relative error of b, expressed as one half of a 95 percent confidence interval.

e_c = Relative error of c, expressed as one half of a 95 percent confidence interval.

(iv) Equation L–2 of this section provides the general formula for calculating the relative errors of sums and differences:

$$e_{SR} = \frac{e_{sA}}{(a+b+c)} \quad \text{(Eq. L-2)}$$

where:

e_{SR} = Relative error of the sum, expressed as one half of a 95 percent confidence interval.

e_{SA} = Absolute error of the sum, expressed as one half of a 95 percent confidence interval.

a+b+c = Sum of the variables measured.

(v) Equation L–3 of this section provides the general formula for calculating the absolute errors of products (e.g., flow rates of GHGs calculated as the product of the flow rate of the stream and the concentration of the GHG in the stream), where the product, P, is the result of multiplying the variables measured, a, b, c, etc. (e.g., P = a*b*c):

$$e_{PA} = (a*b*c)(e_a^2 + e_b^2 + e_c^2)^{1/2} \quad \text{(Eq. L-3)}$$

where:

e_{PA} = Absolute error of the product, expressed as one half of a 95 percent confidence interval.

e_a = Relative error of a, expressed as one half of a 95 percent confidence interval.

e_b = Relative error of b, expressed as one half of a 95 percent confidence interval.

e_c = Relative error of c, expressed as one half of a 95 percent confidence interval.

(vi) Equation L–4 of this section provides the general formula for calculating the relative errors of products:

$$e_{PR} = \frac{e_{PA}}{(a * b * c)} \quad \text{(Eq. L-4)}$$

where:

e_{PR} = Relative error of the product, expressed as one half of a 95 percent confidence interval.

e_{PA} = Absolute error of the product, expressed as one half of a 95 percent confidence interval.

a*b*c = Product of the variables measured.

(vii) Calculate the absolute error of the emissions estimate in terms of CO_2e by performing a preliminary estimate of the annual CO_2e emissions of the process using the method in paragraph (b)(1)(viii) of this section. Multiply this result by the relative error calculated for the mass of fluorine emitted from the process in Equation L–6 of this section.

(viii) To estimate the annual CO_2e emissions of the process for use in the error estimate, apply the methods set forth in paragraphs (b)(2) through (b)(7) and (b)(9) through (b)(16) of this section to representative process measurements. If these process measurements represent less than one year of typical process activity, adjust the estimated emissions to account for one year of typical process activity. To estimate the terms FER_d, FEP, and FEB_k for use in the error estimate for Equations L–11, L–12, and L–13 of this section, you must either use emission testing, monitoring of emitted streams, and/or engineering calculations or assessments, or in the alternative assume that all fluorine is emitted in the form of the fluorinated GHG that has the highest GWP among the fluorinated GHGs that occur in more than trace concentrations in the process. To convert the fluorinated GHG emissions to CO_2e, use Equation A–1 of § 98.2. For fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part, use a default GWP of 2,000.

(2) The total mass of each fluorinated GHG emitted annually from each fluorinated gas production and each fluorinated GHG transformation process must be estimated by using Equation L–5 of this section.

$$E_{FGHGf} = \sum_{p=1}^{n} (E_{Rp-FGHGf} + E_{Pp-FGHGf} + E_{Bp-FGHGf}) \quad \text{(Eq. L-5)}$$

where:

E_{FGHGf} = Total mass of each fluorinated GHG f emitted annually from production or transformation process i (metric tons).

$E_{Rp-FGHGf}$ = Total mass of fluorinated GHG reactant f emitted from production process i over the period p (metric tons, calculated in Equation L–11 of this section).

$E_{Pp-FGHGf}$ = Total mass of the fluorinated GHG product f emitted from production process i over the period p (metric tons, calculated in Equation L–12 of this section).

$E_{Bp-FGHGf}$ = Total mass of fluorinated GHG by-product f emitted from production process i over the period p (metric tons, calculated in Equation L–13 of this section).

n = Number of concentration and flow measurement periods for the year.

(3) The total mass of fluorine emitted from process i over the period p must be estimated at least monthly by calculating the difference between the total mass of fluorine in the reactant(s) (or inputs, for processes that do not involve a chemical reaction) and the total mass of fluorine in the product (or outputs, for processes that do not involve a chemical reaction), accounting for the total mass of fluorine in any destroyed or recaptured streams that contain reactants, products, or by-products (or inputs or outputs). This calculation must be performed using Equation L–6 of this section. An element other than fluorine may be used in the mass-balance equation, provided the element occurs in all of the fluorinated GHGs fed into or generated by the process. In this case, the mass fractions of the element in

the reactants, products, and by-products must be calculated as appropriate for that element.

$$E_F = \sum_{1}^{v} (R_d * MFF_{Rd}) - P * MFF_P - F_D \qquad \text{(Eq. L-6)}$$

where:

E_F = Total mass of fluorine emitted from process i over the period p (metric tons).

R_d = Total mass of the fluorine-containing reactant d that is fed into process i over the period p (metric tons).

P = Total mass of the fluorine-containing product produced by process i over the period p (metric tons).

MFF_{Rd} = Mass fraction of fluorine in reactant d, calculated in Equation L–14 of this section.

MFF_P = Mass fraction of fluorine in the product, calculated in Equation L–15 of this section.

F_D = Total mass of fluorine in destroyed or recaptured streams from process i containing fluorine-containing reactants, products, and by-products over the period p, calculated in Equation L–7 of this section.

v = Number of fluorine-containing reactants fed into process i.

(4) The mass of total fluorine in destroyed or recaptured streams containing fluorine-containing reactants, products, and by-products must be estimated at least monthly using Equation L–7 of this section unless you use the alternative approach provided in paragraph (b)(15) of this section.

$$F_D = \sum_{j=1}^{q} P_j * MFF_P + \sum_{k=1}^{u} \left[\left(\sum_{j=1}^{q} B_{kj} + \sum_{l=1}^{x} B_{kl} \right) * MFF_{Bk} \right] + \sum_{d=1}^{v} \left(\sum_{j=1}^{q} R_{dj} * MFF_{Rd} \right) \qquad \text{(Eq. L-7)}$$

where:

F_D = Total mass of fluorine in destroyed or recaptured streams from process i containing fluorine-containing reactants, products, and by-products over the period p.

P_j = Mass of the fluorine-containing product removed from process i in stream j and destroyed over the period p (calculated in Equation L–8 or L–9 of this section).

B_{kj} = Mass of fluorine-containing by-product k removed from process i in stream j and destroyed over the period p (calculated in Equation L–8 or L–9 of this section).

B_{kl} = Mass of fluorine-containing by-product k removed from process i in stream l and recaptured over the period p.

R_{dj} = Mass of fluorine-containing reactant d removed from process i in stream j and destroyed over the period p (calculated in Equation L–8 or L–9 of this section).

MFF_{Rd} = Mass fraction of fluorine in reactant d, calculated in Equation L–14 of this section.

MFF_P = Mass fraction of fluorine in the product, calculated in Equation L–15 of this section.

MFF_{Bk} = Mass fraction of fluorine in by-product k, calculated in Equation L–16 of this section.

q = Number of streams destroyed in process i.

x = Number of streams recaptured in process i.

u = Number of fluorine-containing by-products generated in process i.

v = Number of fluorine-containing reactants fed into process i.

(5) The mass of each fluorinated GHG removed from process i in stream j and destroyed over the period p (i.e., P_j, B_{kj}, or R_{dj}, as applicable) must be estimated by applying the destruction efficiency of the device that has been demonstrated for the fluorinated GHG f to fluorinated GHG f using Equation L–8 of this section:

$$M_{FGHGfj} = DE_{FGHGf} * c_{FGHGfj} * S_j \quad \text{(Eq. L-8)}$$

where:

M_{FGHGfj} = Mass of fluorinated GHG f removed from process i in stream j and destroyed over the period p. (This may be P_j, B_{kj}, or R_{dj}, as applicable.)

DE_{FGHGf} = Destruction efficiency of the device that has been demonstrated for fluorinated GHG f in stream j (fraction).

C_{FGHGfj} = Concentration (mass fraction) of fluorinated GHG f in stream j removed from process i and fed into the destruction device over the period p. If this concentration is only a trace concentration, $c_{F-GHGfj}$ is equal to zero.

S_j = Mass removed in stream j from process i and fed into the destruction device over the period p (metric tons).

(6) The mass of each fluorine-containing compound that is not a fluorinated GHG and that is removed from process i in stream j and destroyed over the period p (i.e., P_j, B_{kj}, or R_{dj}, as applicable) must be estimated using Equation L–9 of this section.

$$M_{FCgj} = c_{FCgj} * S_j \quad \text{(Eq. L-9)}$$

where:

M_{FCgj} = Mass of non-GHG fluorine-containing compound g removed from process i in stream j and destroyed over the period p. (This may be P_j, B_{kj}, or R_{dj}, as applicable).

c_{FCgj} = Concentration (mass fraction) of non-GHG fluorine-containing compound g in stream j removed from process i and fed into the destruction device over the period p. If this concentration is only a trace concentration, c_{FCgj} is equal to zero.

S_j = Mass removed in stream j from process i and fed into the destruction device over the period p (metric tons).

(7) The mass of fluorine-containing by-product k removed from process i in stream l and recaptured over the period p must be estimated using Equation L–10 of this section:

$$B_{kl} = c_{Bkl} * S_l \quad \text{(Eq. L-10)}$$

where:

B_{kl} = Mass of fluorine-containing by-product k removed from process i in stream l and recaptured over the period p (metric tons).

c_{Bkl} = Concentration (mass fraction) of fluorine-containing by-product k in stream l removed from process i and recaptured over the period p. If this concentration is only a trace concentration, c_{Bkl} is equal to zero.

S_l = Mass removed in stream l from process i and recaptured over the period p (metric tons).

(8) To estimate the terms FER_d, FEP, and FEB_k for Equations L–11, L–12, and L–13 of this section, you must assume that the total mass of fluorine emitted, E_F, estimated in Equation L–6 of this section, occurs in the form of the fluorinated GHG that has the highest GWP among the fluorinated GHGs that occur in more than trace concentrations in the process unless you possess emission characterization measurements showing otherwise. These emission characterization measurements must meet the requirements in paragraph (8)(i), (ii), or (iii) of this section, as appropriate. The sum of the terms must equal 1. You must document the data and calculations that are used to speciate individual compounds and to estimate FER_d, FEP, and FEB_k. Exclude from your calculations the fluorine included in F_D. For example, exclude fluorine-containing compounds that are not fluorinated GHGs and that result from the destruction of fluorinated GHGs by any destruction devices (e.g., the mass of HF created by

combustion of an HFC). However, include emissions of fluorinated GHGs that survive the destruction process.

(i) If the calculations under paragraph (b)(1)(viii) of this section, or any subsequent measurements and calculations under this subpart, indicate that the process emits 25,000 metric tons CO_2e or more, estimate the emissions from each process vent, considering controls, using the methods in §98.123(c)(1). You must characterize the emissions of any process vent that emits 25,000 metric tons CO_2e or more as specified in §98.124(b)(4).

(ii) For other vents, including vents from processes that emit less than 25,000 metric tons CO_2e, you must characterize emissions as specified in §98.124(b)(5).

(iii) For fluorine emissions that are not accounted for by vent estimates, you must characterize emissions as specified in §98.124(b)(6).

(9) The total mass of fluorine-containing reactant d emitted must be estimated at least monthly based on the total fluorine emitted and the fraction that consists of fluorine-containing reactants using Equation L–11 of this section. If the fluorine-containing reactant d is a non-GHG, you may assume that FER_d is zero.

$$E_{R-ip} = \frac{FER_d * E_F}{\left(\sum_{d=1}^{v} FER_d * MFF_{Rd} + FEP * MFF_P + \sum_{k=1}^{u} FEB_k * MFF_{Bk}\right)} \quad \text{(Eq. L-11)}$$

where:

E_{R-ip} = Total mass of fluorine-containing reactant d that is emitted from process i over the period p (metric tons).

FER_d = The fraction of the mass emitted that consists of the fluorine-containing reactant d.

E_F = Total mass of fluorine emissions from process i over the period p (metric tons), calculated in Equation L–6 of this section.

FEP = The fraction of the mass emitted that consists of the fluorine-containing product.

FEB_k = The fraction of the mass emitted that consists of fluorine-containing by-product k.

MFF_{Rd} = Mass fraction of fluorine in reactant d, calculated in Equation L–14 of this section.

MFF_P = Mass fraction of fluorine in the product, calculated in Equation L–15 of this section.

MFF_{Bk} = Mass fraction of fluorine in by-product k, calculation in Equation L–16 of this section.

u = Number of fluorine-containing by-products generated in process i.

v = Number of fluorine-containing reactants fed into process i.

(10) The total mass of fluorine-containing product emitted must be estimated at least monthly based on the total fluorine emitted and the fraction that consists of fluorine-containing products using Equation L–12 of this section. If the fluorine-containing product is a non-GHG, you may assume that FEP is zero.

$$E_{P-ip} = \frac{FEP * E_F}{\left(\sum_{d=1}^{v} FER_d * MFF_{Rd} + FEP * MFF_P + \sum_{k=1}^{u} FEB_k * MFF_{Bk}\right)} \quad \text{(Eq. L-12)}$$

where:

E_{P-ip} = Total mass of fluorine-containing product emitted from process i over the period p (metric tons).

FEP = The fraction of the mass emitted that consists of the fluorine-containing product.

E_F = Total mass of fluorine emissions from process i over the period p (metric tons), calculated in Equation L–6 of this section.

FER_d = The fraction of the mass emitted that consists of fluorine-containing reactant d.

FEB_k = The fraction of the mass emitted that consists of fluorine-containing by-product k.

MFF_{Rd} = Mass fraction of fluorine in reactant d, calculated in Equation L–14 of this section.

MFF_P = Mass fraction of fluorine in the product, calculated in Equation L–15 of this section.

MFF_{Bk} = Mass fraction of fluorine in by-product k, calculation in Equation L–16 of this section.

u = Number of fluorine-containing by-products generated in process i.

v = Number of fluorine-containing reactants fed into process i.

(11) The total mass of fluorine-containing by-product k emitted must be estimated at least monthly based on the total fluorine emitted and the fraction that consists of fluorine-containing by-products using Equation L–13 of this section. If fluorine-containing by-product k is a non-GHG, you may assume that FEB_k is zero.

$$E_{Bk-ip} = \frac{FEB_k * E_F}{\left(\sum_{1}^{v} FER_d * MFF_{Rd} + FEP * MFF_P + \sum_{k=1}^{u} FEB_k * MFF_{Bk} \right)} \quad \text{(Eq. L-13)}$$

where:

$E_{Bk\text{-}ip}$ = Total mass of fluorine-containing by-product k emitted from process i over the period p (metric tons).

FEB_k = The fraction of the mass emitted that consists of fluorine-containing by-product k.

FER_d = The fraction of the mass emitted that consists of fluorine-containing reactant d.

FEP = The fraction of the mass emitted that consists of the fluorine-containing product.

E_F = Total mass of fluorine emissions from process i over the period p (metric tons), calculated in Equation L–6 of this section.

MFF_{Rd} = Mass fraction of fluorine in reactant d, calculated in Equation L–14 of this section.

MFF_P = Mass fraction of fluorine in the product, calculated in Equation L–15 of this section.

MFF_{Bk} = Mass fraction of fluorine in by-product k, calculation in Equation L–16 of this section.

u = Number of fluorine-containing by-products generated in process i.

v = Number of fluorine-containing reactants fed into process i.

(12) The mass fraction of fluorine in reactant d must be estimated using Equation L–14 of this section:

$$MFF_{Rd} = MF_{Rd} * \frac{AW_F}{MW_{Rd}} \quad \text{(Eq. L-14)}$$

where:

MFF_{Rd} = Mass fraction of fluorine in reactant d (fraction).

MF_{Rd} = Moles fluorine per mole of reactant d.

AW_F = Atomic weight of fluorine.

MW_{Rd} = Molecular weight of reactant d.

(13) The mass fraction of fluorine in the product must be estimated using Equation L–15 of this section:

$$MFF_P = MF_P * \frac{AW_F}{MW_P} \quad \text{(Eq. L-15)}$$

where:

MFF_P = Mass fraction of fluorine in the product (fraction).

MF_P = Moles fluorine per mole of product.

AW_F = Atomic weight of fluorine.

MW_P = Molecular weight of the product produced.

(14) The mass fraction of fluorine in by-product k must be estimated using Equation L–16 of this section:

$$MFF_{Bk} = MF_{Bk} * \frac{AW_F}{MW_{Bk}} \quad \text{(Eq. L-16)}$$

where:

MFF_{Bk} = Mass fraction of fluorine in the product (fraction).

MF_{Bk} = Moles fluorine per mole of by-product k.

AW_F = Atomic weight of fluorine.

MW_{Bk} = Molecular weight of by-product k.

(15) *Alternative for determining the mass of fluorine destroyed or recaptured.* As an alternative to using Equation L–7 of this section as provided in paragraph (b)(4) of this section, you may estimate at least monthly the total mass of fluorine in destroyed or recaptured streams containing fluorine-containing compounds (including all fluorine-containing reactants, products, and by-products) using Equation L–17 of this section.

$$F_D = \sum_{j=1}^{q} DE_{avgj} * c_{TFj} * S_j + \sum_{l=1}^{x} c_{TFl} * S_l \quad \text{(Eq. L-17)}$$

where:

F_D = Total mass of fluorine in destroyed or recaptured streams from process i containing fluorine-containing reactants, products, and by-products over the period p.

DE_{avgj} = Weighted average destruction efficiency of the destruction device for the fluorine-containing compounds identified in destroyed stream j under § 98.124(b)(4)(ii) and (5)(ii) (calculated in Equation L–18 of this section)(fraction).

c_{TFj} = Concentration (mass fraction) of total fluorine in stream j removed from process i and fed into the destruction device over the period p. If this concentration is only a trace concentration, c_{TFj} is equal to zero.

S_j = Mass removed in stream j from process i and fed into the destruction device over the period p (metric tons).

c_{TFl} = Concentration (mass fraction) of total fluorine in stream l removed from process i and recaptured over the period p. If this concentration is only a trace concentration, c_{Bkl} is equal to zero.

S_l = Mass removed in stream l from process i and recaptured over the period p.

q = Number of streams destroyed in process i.

x = Number of streams recaptured in process i.

(16) *Weighted average destruction efficiency.* For purposes of Equation L–17 of this section, calculate the weighted average destruction efficiency applicable to a destroyed stream using Equation L–18 of this section.

$$DE_{avgj} = \frac{\sum_{f=1}^{w} DE_{FGHGf} * c_{FGHGf} * S_j * MFF_{FGHGf} + \sum_{g=1}^{y} c_{FCg} * S_j * MFF_g}{\sum_{f=1}^{w} c_{FGHGf} * S_j * MFF_{FGHGf} + \sum_{g=1}^{y} c_{FCg} * S_j * MFF_g} \quad \text{(Eq. L-18)}$$

where:

DE_{avgj} = Weighted average destruction efficiency of the destruction device for the fluorine-containing compounds identified in destroyed stream j under 98.124(b)(4)(ii) or (b)(5)(ii), as appropriate.

DE_{FGHGf} = Destruction efficiency of the device that has been demonstrated for fluorinated GHG f in stream j (fraction).

c_{FGHGfj} = Concentration (mass fraction) of fluorinated GHG f in stream j removed from process i and fed into the destruction device over the period p. If this concentration is only a trace concentration, $c_{F\text{–}GHGfj}$ is equal to zero.

c_{FCgj} = Concentration (mass fraction) of non-GHG fluorine-containing compound g in stream j removed from process i and fed into the destruction device over the period p. If this concentration is only a trace concentration, c_{FCgj} is equal to zero.

S_j = Mass removed in stream j from process i and fed into the destruction device over the period p (metric tons).

MFF_{FGHGf} = Mass fraction of fluorine in fluorinated GHG f, calculated in Equation L–14, L–15, or L–16 of this section, as appropriate.

MFF_{FCg} = Mass fraction of fluorine in non-GHG fluorine-containing compound g, calculated in Equation L–14, L–15, or L–16 of this section, as appropriate.

w = Number of fluorinated GHGs in destroyed stream j.

y = Number of non-GHG fluorine-containing compounds in destroyed stream j.

(c) *Emission factor and emission calculation factor methods.* To use the method in this paragraph for batch processes, you must comply with either paragraph (c)(3) of this section (Emission Factor approach) or paragraph (c)(4) of this section (Emission Calculation Factor approach). To use the method in this paragraph for continuous processes, you must first make a preliminary estimate of the emissions from each individual continuous process vent under paragraph (c)(1) of this section. If your continuous process operates under different conditions as part of normal operations, you must also define the different operating scenarios and make a preliminary estimate of the emissions from the vent for each operating scenario. Then, compare the preliminary estimate for each continuous process vent (summed across operating scenarios) to the criteria in paragraph (c)(2) of this section to determine whether the process vent meets the criteria for using the emission factor method described in paragraph (c)(3) of this section or whether the process vent meets the criteria for using the emission calculation factor method described in paragraph (c)(4) of this section. For continuous process vents that meet the criteria for using the emission factor method described in paragraph (c)(3) of this section and that have more than one operating scenario, compare the preliminary estimate for each operating scenario to the criteria in (c)(3)(ii) to determine whether an emission factor must be developed for that operating scenario.

(1) *Preliminary estimate of emissions by process vent.* You must estimate the annual CO_2e emissions of fluorinated GHGs for each process vent within each operating scenario of a continuous process using the approaches specified in paragraph (c)(1)(i) or (c)(1)(ii) of this section, accounting for any destruction as specified in paragraph (c)(1)(iii) of this section. You must determine emissions of fluorinated GHGs by process vent by using measurements, by using calculations based on chemical engineering principles and chemical property data, or by conducting an engineering assessment. You may use previous measurements, calculations, and assessments if they represent current process operating conditions or process operating conditions that would result in higher fluorinated GHG emissions than the current operating conditions and if they were performed in accordance with paragraphs (c)(1)(i), (c)(1)(ii), and (c)(1)(iii) of this section, as applicable. You must document all data, assumptions, and procedures used in the calculations or engineering assessment and keep a record of the emissions determination as required by § 98.127(a).

(i) *Engineering calculations.* For process vent emission calculations, you may use any of paragraphs (c)(1)(i)(A), (c)(1)(i)(B), or (c)(1)(i)(C) of this section.

(A) U.S. Environmental Protection Agency, Emission Inventory Improvement Program, Volume II: Chapter 16, Methods for Estimating Air Emissions from Chemical Manufacturing Facilities, August 2007, Final (incorporated by reference, see § 98.7).

(B) You may determine the fluorinated GHG emissions from any process vent within the process using the procedures specified in § 63.1257(d)(2)(i) and (d)(3)(i)(B) of this chapter, except as specified in paragraphs (c)(1)(i)(B)(*1*) through (c)(1)(i)(B)(*4*) of this section. For the purposes of this subpart, use of the term ''HAP'' in § 63.1257(d)(2)(i) and (d)(3)(i)(B) of this chapter means ''fluorinated GHG''.

(*1*) To calculate emissions caused by the heating of a vessel without a process condenser to a temperature lower than the boiling point, you must use the procedures in § 63.1257(d)(2)(i)(C)(*3*) of this chapter.

(*2*) To calculate emissions from depressurization of a vessel without a process condenser, you must use the procedures in § 63.1257(d)(2)(i)(D)(*10*) of this chapter.

(*3*) To calculate emissions from vacuum systems, the terms used in Equation 33 to § 63.1257(d)(2)(i)(E) of this chapter are defined as follows:

(*i*) P_{system} = Absolute pressure of the receiving vessel.

(*ii*) P_i= Partial pressure of the fluorinated GHG determined at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver.

(*iii*) P_j= Partial pressure of condensables (including fluorinated GHG) determined at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver.

(*iv*) $MW_{Fluorinated\ GHG}$= Molecular weight of the fluorinated GHG determined at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver.

(*4*) To calculate emissions when a vessel is equipped with a process condenser or a control condenser, you must use the procedures in § 63.1257(d)(3)(i)(B) of this chapter, except as follows:

(*i*) You must determine the flowrate of gas (or volume of gas), partial pressures of condensables, temperature (T), and fluorinated GHG molecular weight ($MW_{Fluorinated\ GHG}$) at the exit temperature and exit pressure conditions of the condenser or at the conditions of the dedicated receiver.

(*ii*) You must assume that all of the components contained in the condenser exit vent stream are in equilibrium with the same components in the exit condensate stream (except for noncondensables).

(*iii*) You must perform a material balance for each component, if the condensate receiver composition is not known.

(*iv*) For the emissions from gas evolution, the term for time, t, must be used in Equation 12 to § 63.1257(d)(2)(i)(B) of this chapter.

(*v*) Emissions from empty vessel purging must be calculated using Equation 36 to § 63.1257(d)(2)(i)(H) of this chapter and the exit temperature and exit pressure conditions of the condenser or the conditions of the dedicated receiver.

(C) Commercial software products that follow chemical engineering principles (e.g., including the calculation methodologies in paragraphs (c)(1)(i)(A) and (c)(1)(i)(B) of this section).

(ii) *Engineering assessments.* For process vent emissions determinations, you may conduct an engineering assessment to calculate uncontrolled emissions. An engineering assessment includes, but is not limited to, the following:

(A) Previous test results, provided the tests are representative of current operating practices of the process.

(B) Bench-scale or pilot-scale test data representative of the process operating conditions.

(C) Maximum flow rate, fluorinated GHG emission rate, concentration, or other relevant parameters specified or implied within a permit limit applicable to the process vent.

(D) Design analysis based on chemical engineering principles, measureable process parameters, or physical or chemical laws or properties.

(iii) *Impact of destruction for the preliminary estimate.* If the process vent is vented to a destruction device, you may reflect the impact of the destruction device on emissions. In your emissions estimate, account for the following:

(A) The destruction efficiencies of the device that have been demonstrated for the fluorinated GHGs in the vent stream for periods when the process vent is vented to the destruction device.

(B) Any periods when the process vent is not vented to the destruction device.

(iv) *Use of typical recent values.* In the calculations in paragraphs (c)(1)(i), (c)(1)(ii), and (c)(1)(iii) of this section, the values used for the expected process activity and for the expected fraction of that activity whose emissions will be vented to the properly functioning destruction device must be based on either typical recent values for the process or values that would overestimate emissions from the process, unless there is a compelling reason to adopt a different value (e.g., installation of a destruction device for a previously uncontrolled process). If there is such a reason, it must be documented in the GHG Monitoring Plan.

(v) *GWPs.* To convert the fluorinated GHG emissions to CO_2e, use Equation A–1 of §98.2. For fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part, use a default GWP of 2,000 unless you submit a request to use other GWPs for those fluorinated GHGs in that process under paragraph (c)(1)(vi) of this section and we approve that request.

(vi) *Request to use a GWP other than 2,000 for fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part.* If your process vent emits one or more fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part, that are emitted in quantities that, with a default GWP of 2,000, result in total calculated annual emissions equal to or greater than 10,000 metric tons CO_2e for the vent, and that you believe have GWPs that would result in total calculated annual emissions less than 10,000 metric tons CO_2e for the vent, you may submit a request to use provisional GWPs for these fluorinated GHGs for purposes of the calculations in paragraph (c)(1) of this section. The request must be submitted by February 28, 2011 for a completeness determination and review by EPA.

(A) *Contents of the request.* You must include the following information in the request for each fluorinated GHG that does not have a GWP listed in Table A–1 to subpart A of this part and that constitutes more than one percent by mass of the stream emitted from the vent:

(*1*) The identity of the fluorinated GHG, including its chemical formula and, if available, CAS number.

(*2*) The estimated GWP of the fluorinated GHG.

(*3*) The data and analysis that supports your estimate of the GWP of the fluorinated GHG, including:

(*i*) Data and analysis related to the low-pressure gas phase infrared absorption spectrum of the fluorinated GHG.

(*ii*) Data and analysis related to the estimated atmospheric lifetime of the fluorinated GHG (reaction mechanisms and rates, including e.g., photolysis and reaction with atmospheric components such as OH, O_3, CO, and water).

(*iii*) The radiative transfer analysis that integrates the lifetime and infrared absorption spectrum data to calculate the GWP.

(*iv*) Any published or unpublished studies of the GWP of the gas.

(*4*) The engineering calculations or assessments and underlying data that demonstrate that the process vent is calculated to emit less than 10,000 metric tons CO_2e of this and other fluorinated GHGs only when the proposed provisional GWPs, not the default GWP of 2,000, are used for fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part.

(B) *Review and completeness determination by EPA.* If EPA makes a preliminary determination that the request is complete, that it substantiates each of the provisional GWPs, and that it demonstrates that the process vent is calculated to emit less than 10,000 metric tons CO_2e of this and other fluorinated GHGs only when the provisional GWPs, not the default GWP of 2,000, are used for fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part, then EPA will publish a notice including the data and analysis submitted under paragraphs (c)(1)(vi)(A)(1) through (c)(1)(vi)(A)(3) of this section. If, after review of public comment on the notice, EPA finalizes its preliminary determination, then EPA will permit the facility to use the provisional GWPs for the calculations in paragraph (c)(1) of this section unless and until EPA determines that one or more of the provisional GWPs is in error and provides reasonable notice to the facility.

(2) *Method selection for continuous process vents.* (i) If the calculations under paragraph (c)(1) of this section, as well as any subsequent measurements and calculations under this subpart, indicate that the continuous process vent has fluorinated GHG emissions of less than 10,000 metric ton CO_2e per year, summed across all operating scenarios, then you may comply with either paragraph (c)(3) of this section (Emission Factor approach) or paragraph (c)(4) of this section (Emission Calculation Factor approach).

(ii) If the continuous process vent does not meet the criteria in paragraph (c)(2)(i) of this section, then you must comply with the emission factor method specified in paragraph (c)(3) (Emission Factor approach) of this section.

(A) You must conduct emission testing for process-vent-specific emission factor development before the destruction device unless the calculations you performed under paragraph (c)(1)(iii) of this section indicate that the uncontrolled fluorinated GHG emissions that occur during periods when the process vent is not vented to the properly functioning destruction device are less than 10,000 metric tons CO_2e per year. In this case, you may conduct emission testing after the destruction device to develop a process-vent-specific emission factor. If you do so, you must develop and apply an emission calculation factor under paragraph (c)(4) to estimate emissions during any periods when the process vent is not vented to the properly functioning destruction device.

(B) Regardless of the level of uncontrolled emissions, the emission testing for process-vent-specific emission factor development may be conducted on the outlet side of a wet scrubber in place for acid gas reduction, if one is in place, as long as there is no appreciable reduction in the fluorinated GHG.

(3) *Process-vent-specific emission factor method.* For each process vent, conduct an emission test and measure fluorinated GHG emissions from the process and measure the process activity, such as the feed rate, production rate, or other process activity rate, during the test as described in this paragraph (c)(3). Conduct the emission test according to the procedures in § 98.124. All emissions test data and procedures used in developing emission factors must be documented according to § 98.127. If more than one operating scenario applies to the process that contains the subject process vent, you must comply with either paragraph (3)(i) or paragraph (3)(ii) of this section.

(i) Conduct a separate emissions test for operation under each operating scenario.

(ii) Conduct an emissions test for the operating scenario that is expected to have the largest emissions in terms of CO_2e (considering both activity levels and emission calculation factors) on an annual basis. Also conduct an emissions test for each additional operating scenario that is estimated to emit 10,000 metric tons CO_2e or more annually from the vent and whose emission calculation factor differs by 15 percent or more from the emission calculation factor of the operating scenario that is expected to have the largest emissions (or of another operating scenario for which emission testing is performed), unless the difference between the operating scenarios is solely due to the application of a destruction device to emissions under one of the operating scenarios. For any other operating scenarios, adjust the process-vent specific emission factor developed for the operating scenario that is expected to have the largest emissions (or for another operating scenario for which emission testing is performed) using the approach in paragraph (c)(3)(viii) of this section.

(iii) You must measure the process activity, such as the process feed rate, process production rate, or other process activity rate, as applicable, during the emission test and calculate the rate for the test period, in kg (or another appropriate metric) per hour.

(iv) For continuous processes, you must calculate the hourly emission rate of each fluorinated GHG using Equation L–19 of this section and determine the hourly emission rate of each fluorinated GHG per process vent (and per operating scenario, as applicable) for the test run.

$$E_{ContPV} = \frac{C_{PV}}{10^6} * MW * Q_{PV} * \frac{1}{SV} * \frac{1}{10^3} * \frac{60}{1} \quad \text{(Eq. L-19)}$$

where:

E_{ContPV} = Mass of fluorinated GHG f emitted from process vent v from process i, operating scenario j, during the emission test during test run r (kg/hr).

C_{PV} = Concentration of fluorinated GHG f during test run r of the emission test (ppmv).

MW = Molecular weight of fluorinated GHG f (g/g-mole).

Q_{PV} = Flow rate of the process vent stream during test run r of the emission test (m^3/min).

SV = Standard molar volume of gas (0.0240 m^3/g-mole at 68 °F and 1 atm).

$1/10^3$ = Conversion factor (1 kilogram/1,000 grams).

60/1 = Conversion factor (60 minutes/1 hour).

(v) You must calculate a site-specific, process-vent-specific emission factor for each fluorinated GHG for each process vent and each operating scenario, in kg of fluorinated GHG per process activity rate (e.g., kg of feed or production), as applicable, using Equation L–20 of this section. For continuous processes, divide the hourly fluorinated GHG emission rate during the test by the hourly process activity rate during the test runs.

$$EF_{PV} = \frac{\sum_{1}^{r}\left(\frac{E_{PV}}{Activity_{EmissionTest}}\right)}{r} \quad \text{(Eq. L-20)}$$

where:

EF_{PV} = Emission factor for fluorinated GHG f emitted from process vent v during process i, operating scenario j (e.g., kg emitted/kg activity).

E_{PV} = Mass of fluorinated GHG f emitted from process vent v from process i, operating scenario j, during the emission test during test run r, for either continuous or batch (kg emitted/hr for continuous, kg emitted/batch for batch).

$Activity_{EmissionTest}$ = Process feed, process production, or other process activity rate for process i, operating scenario j, during the emission test during test run r (e.g., kg product/hr).

r = Number of test runs performed during the emission test.

(vi) If you conducted emissions testing after the destruction device, you must calculate the emissions of each fluorinated GHG for the process vent (and operating scenario, as applicable) using Equation L–21 of this section. You must also develop a process-vent-specific emission calculation factor based on paragraph (c)(4) of this section for the periods when the process vent is not venting to the destruction device.

$$E_{PV} = EF_{PV-C} * Activity_C + ECF_{PV-U} * Activity_U \quad \text{(Eq. L-21)}$$

where:

E_{PV} = Mass of fluorinated GHG f emitted from process vent v from process i, operating scenario j, for the year (kg).

EF_{PV-C} = Emission factor for fluorinated GHG f emitted from process vent v during process i, operating scenario j, based on testing after the destruction device (kg emitted/activity) (e.g., kg emitted/kg product).

$Activity_C$ = Total process feed, process production, or other process activity for process i, operating scenario j, during the year for which emissions are vented to the properly functioning destruction device (i.e., controlled).

ECF_{PV-U} = Emission calculation factor for fluorinated GHG f emitted from process vent v during process i, operating scenario j during periods when the process vent is not vented to the properly functioning destruction device (kg emitted/activity) (e.g., kg emitted/kg product).

$Activity_U$ = Total process feed, process production, or other process activity during the year for which the process vent is not vented to the properly functioning destruction device (e.g., kg product).

(vii) If you conducted emissions testing before the destruction device, apply the destruction efficiencies of the device that have been demonstrated for the fluorinated GHGs in the vent stream to the fluorinated GHG emissions for the process vent (and operating scenario, as applicable), using Equation L–22 of this section. You may apply the destruction efficiency only to the portion of the process activity during which emissions are vented to the properly functioning destruction device (i.e., controlled).

$$E_{PV} = EF_{PV-U} * \left(Activity_U + Activity_C * (1 - DE)\right) \quad \text{(Eq. L-22)}$$

where:

E_{PV} = Mass of fluorinated GHG f emitted from process vent v from process i, operating scenario j, for the year, considering destruction efficiency (kg).

EF_{PV-U} = Emission factor (uncontrolled) for fluorinated GHG f emitted from process vent v during process i, operating scenario j (kg emitted/kg product).

$Activity_U$ = Total process feed, process production, or other process activity for process i, operating scenario j, during the year for which the process vent is not vented to the properly functioning destruction device (e.g., kg product).

$Activity_C$ = Total process feed, process production, or other process activity for process i, operating scenario j, during the year for which the process vent is vented to the properly functioning destruction device (e.g., kg product).

DE = Demonstrated destruction efficiency of the destruction device (weight fraction).

(viii) *Adjusted process-vent-specific emission factors for other operating scenarios.* For process vents from processes with multiple operating scenarios, use Equation L–23 of this section to develop an adjusted process-vent-specific emission factor for each operating scenario from which the vent is estimated to emit less than 10,000 metric tons CO_2e annually or whose emission calculation factor differs by less than 15 percent from the emission calculation factor of the operating scenario that is expected to have the largest emissions (or of another operating scenario for which emission testing is performed).

$$EF_{PVadj} = \frac{ECF_{UT}}{ECF_T} * EF_{PV} \quad \text{(Eq. L-23)}$$

where:

EF_{PVadj} = Adjusted process-vent-specific emission factor for an untested operating scenario.

ECF_{UT} = Emission calculation factor for the untested operating scenario developed under paragraph (c)(4) of this section.

ECF_T = Emission calculation for the tested operating scenario developed under paragraph (c)(4) of this section.

EF_{PV} = Process vent specific emission factor for the tested operating scenario.

(ix) Sum the emissions of each fluorinated GHG from all process vents in each operating scenario and all operating scenarios in the process for the year to estimate the total process vent emissions of each fluorinated GHG from the process, using Equation L–24 of this section.

$$E_{Pfi} = \sum_{1}^{o} \sum_{1}^{v} E_{PV} \quad \text{(Eq. L-24)}$$

where:

E_{Pfi} = Mass of fluorinated GHG f emitted from process vents for process i for the year (kg).

E_{PV} = Mass of fluorinated GHG f emitted from process vent v from process i, operating scenario j, for the year, considering destruction efficiency (kg).

v = Number of process vents in process i, operating scenario j.

o = Number of operating scenarios for process i.

(4) *Process-vent-specific emission calculation factor method.* For each process vent within an operating scenario, determine fluorinated GHG emissions by calculations and determine the process activity rate, such as the feed rate, production rate, or other process activity rate, associated with the emission rate.

(i) You must calculate uncontrolled emissions of fluorinated GHG by individual process vent, E_{PV}, by using measurements, by using calculations based on chemical engineering principles and chemical property data, or by conducting an engineering assessment. Use the procedures in paragraphs (c)(1)(i) or (ii) of this section, except paragraph (c)(1)(ii)(C) of this section. The procedures in paragraphs (c)(1)(i) and (ii) of this section may be applied either to batch process vents or to continuous process vents. The uncontrolled emissions must be based on a typical batch or production rate under a defined operating scenario. The process activity rate associated with the uncontrolled emissions must be determined. The methods, data, and assumptions used to estimate emissions for each operating scenario must be selected to yield a best estimate (expected value) of emissions rather than an over- or underestimate of emissions for that operating scenario. All data, assumptions, and procedures used in the calculations or engineering assessment must be documented according to § 98.127.

(ii) You must calculate a site-specific, process-vent-specific emission calculation factor for each process vent, each operating scenario, and each fluorinated GHG, in kg of fluorinated GHG per activity rate (e.g., kg of feed or production) as applicable, using Equation L–25 of this section.

$$ECF_{PV} = \frac{E_{PV}}{Activity_{\mathrm{Re}\, presentative}} \quad \text{(Eq. L-25)}$$

where:

ECF_{PV} = Emission calculation factor for fluorinated GHG f emitted from process vent v during process i, operating scenario j, (e.g., kg emitted/kg product).

E_{PV} = Average mass of fluorinated GHG f emitted, based on calculations, from process vent v from process i, operating scenario j, during the period or batch for which emissions were calculated, for either continuous or batch (kg emitted/hr for continuous, kg emitted/batch for batch).

$Activity_{Representative}$ = Process feed, process production, or other process activity rate corresponding to average mass of emissions based on calculations (e.g., kg product/hr for continuous, kg product/batch for batch).

(iii) You must calculate emissions of each fluorinated GHG for the process vent (and operating scenario, as applicable) for the year by multiplying the process-vent-specific emission calculation factor by the total process activity, as applicable, for the year, using Equation L–26 of this section.

$$E_{PV} = ECF_{PV} * Activity \quad \text{(Eq. L-26)}$$

where:

E_{PV} = Mass of fluorinated GHG f emitted from process vent v from process i, operating scenario j, for the year (kg).

ECF_{PV} = Emission calculation factor for fluorinated GHG f emitted from process vent v during process i, operating scenario j, (kg emitted/activity) (e.g., kg emitted/kg product).

Activity = Process feed, process production, or other process activity for process i, operating scenario j, during the year.

(iv) If the process vent is vented to a destruction device, apply the demonstrated destruction efficiency of the device to the fluorinated GHG emissions for the process vent (and operating scenario, as applicable), using Equation L–27 of this section. Apply the destruction efficiency only to the portion of the process activity that is vented to the properly functioning destruction device (i.e., controlled).

$$E_{PV} = ECF_{PV} * \left(Activity_U + Activity_C * (1 - DE)\right) \quad \text{(Eq. L-27)}$$

where:

E_{PV} = Mass of fluorinated GHG f emitted from process vent v from process i, operating scenario j, for the year considering destruction efficiency (kg).

ECF_{PV} = Emission calculation factor for fluorinated GHG f emitted from process vent v during process i, operating scenario j, (e.g., kg emitted/kg product).

$Activity_U$ = Total process feed, process production, or other process activity for process i, operating scenario j, during the year for which the process vent is not vented to the properly functioning destruction device (e.g., kg product).

$Activity_C$ = Total process feed, process production, or other process activity for process i, operating scenario j, during the year for which the process vent is vented to the properly functioning destruction device (e.g., kg product).

DE = Demonstrated destruction efficiency of the destruction device (weight fraction).

(v) Sum the emissions of each fluorinated GHG from all process vents in each operating scenario and all operating scenarios in the process for the year to estimate the total process vent emissions of each fluorinated GHG from the process, using Equation L–28 of this section.

$$E_{Pfi} = \sum_{1}^{o} \sum_{1}^{v} E_{PV} \quad \text{(Eq. L-28)}$$

where:

E_{Pfi} = Mass of fluorinated GHG f emitted from process vents for process i for the year (kg).

E_{PV} = Mass of fluorinated GHG f emitted from process vent v from process i, operating scenario j, for the year, considering destruction efficiency (kg).

v = Number of process vents in process i, operating scenario j.

o = Number of operating scenarios in process i.

(d) *Calculate fluorinated GHG emissions for equipment leaks (EL).* If you comply with paragraph (c) of this section, you must calculate the fluorinated GHG emissions from pieces of equipment associated with processes covered under this subpart and in fluorinated GHG service. If you conduct monitoring of equipment in fluorinated GHG service, monitoring must be conducted for those in light liquid and in gas and vapor service. If you conduct monitoring of equipment in fluorinated GHG service, you may exclude from monitoring each piece of equipment that is difficult-to-monitor, that is unsafe-to-monitor, that is insulated, or that is in heavy liquid service; you may exclude from monitoring each pump with dual mechanical seals, agitator with dual mechanical seals, pump with no external shaft, agitator with no external shaft; you may exclude from monitoring each pressure relief device in gas and vapor service with upstream rupture disk, each sampling connection system with closed-loop or closed-purge systems, and any pieces of equipment where leaks are routed through a closed vent system to a destruction device. You must estimate emissions using another approach for those pieces of equipment excluded from monitoring. Equipment that is in fluorinated GHG service for less than 300 hr/yr; equipment that is in vacuum service; pressure relief devices that are in light liquid service; and instrumentation systems are exempted from these requirements.

(1) The emissions from equipment leaks must be calculated using any of the procedures in paragraphs (d)(1)(i), (d)(1)(ii), (d)(1)(iii), or (d)(1)(iv) of this section.

(i) *Use of Average Emission Factor Approach in EPA Protocol for Equipment Leak Emission Estimates.* The emissions from equipment leaks may be calculated using the default Average Emission Factor Approach in EPA–453/R–95–017 (incorporated by reference, see § 98.7).

(ii) *Use of Other Approaches in EPA Protocol for Equipment Leak Emission Estimates in conjunction with EPA Method 21 at 40 CFR part 60, appendix A–7.* The emissions from equipment leaks may be calculated using one of the following methods in EPA–453/R–95–017 (incorporated by reference, see § 98.7): The Screening Ranges Approach; the EPA Correlation Approach; or the Unit-Specific Correlation Approach. If you determine that EPA Method 21 at 40 CFR part 60, appendix A–7 is appropriate for monitoring a fluorinated GHG, and if you calibrate your instrument with a compound different from one or more of the fluorinated GHGs or surrogates to be measured, you must develop response factors for each fluorinated GHG or for each surrogate to be measured using EPA Method 21 at 40 CFR part 60, appendix A–7. For each fluorinated GHG or surrogate measured, the response factor must be less than 10. The response factor is the ratio of the known concentration of a fluorinated GHG or surrogate to the observed meter reading when measured using an instrument calibrated with the reference compound.

(iii) *Use of Other Approaches in EPA Protocol for Equipment Leak Emission Estimates in conjunction with site-specific leak monitoring methods.* The emissions from equipment leaks may be calculated using one of the following methods in EPA–453/R–95–017 (incorporated by reference, see § 98.7): The Screening Ranges Approach; the EPA Correlation Approach; or the Unit-Specific Correlation Approach. You may develop a site-specific leak monitoring method appropriate for monitoring fluorinated GHGs or surrogates to use along with these three approaches. The site-specific leak monitoring method must meet the requirements in § 98.124(f)(1).

(iv) *Use of site-specific leak monitoring methods.* The emissions from equipment leaks may be calculated using a site-specific leak monitoring method. The site-specific leak monitoring method must meet the requirements in § 98.124(f)(1).

(2) You must collect information on the number of each type of equipment; the service of each piece of equipment (gas, light liquid, heavy liquid); the concentration of each fluorinated GHG in the stream; and the time period each piece of equipment was in service. Depending on which approach you follow, you may be required to collect information for equipment on the associated screening data concentrations for greater than or equal to 10,000 ppmv and associated screening data concentrations for less than 10,000 ppmv; associated actual screening data concentrations; or associated screening data and leak rate data (i.e., bagging) used to develop a unit-specific correlation.

(3) Calculate and sum the emissions of each fluorinated GHG in metric tons per year for equipment pieces for each process, E_{ELf}, annually. You must include and estimate emissions for types of equipment that are excluded from monitoring, including difficult-to-monitor, unsafe-to-monitor and insulated pieces of equipment, pieces of equipment in heavy liquid service, pumps

with dual mechanical seals, agitators with dual mechanical seals, pumps with no external shaft, agitators with no external shaft, pressure relief devices in gas and vapor service with upstream rupture disk, sampling connection systems with closed-loop or closed purge systems, and pieces of equipment where leaks are routed through a closed vent system to a destruction device.

(e) *Calculate total fluorinated GHG emissions for each process and for production or transformation processes at the facility.* (i) Estimate annually the total mass of each fluorinated GHG emitted from each process, including emissions from process vents in paragraphs (c)(3) and (c)(4) of this section, as appropriate, and from equipment leaks in paragraph (d), using Equation L–29 of this section.

$$E_i = E_{Pfi} + E_{ELfi} \quad \text{(Eq. L-29)}$$

where:

E_i = Total mass of each fluorinated GHG f emitted from process i, annual basis (kg/year).

E_{Pfi} = Mass of fluorinated GHG f emitted from all process vents and all operating scenarios in process i, annually (kg/year, calculated in Equation L–24 or L–28 of this section, as appropriate).

E_{ELfi} = Mass of fluorinated GHG f emitted from equipment leaks for pieces of equipment for process i, annually (kg/year, calculated in paragraph (d)(3) of this section).

(ii) Estimate annually the total mass of each fluorinated GHG emitted from each type of production or transformation process at the facility using Equation L–30 of this section. Develop separate totals for fluorinated gas production processes, transformation processes that transform fluorinated gases produced at the facility, and transformation processes that transform fluorinated gases produced at another facility.

$$E = \sum_{i=1}^{z} E_i * 0.001 \quad \text{(Eq. L-30)}$$

where:

E = Total mass of each fluorinated GHG f emitted from all fluorinated gas production processes, all transformation processes that transform fluorinated gases produced at the facility, or all transformation processes that transform fluorinated gases produced at another facility, as appropriate (metric tons).

E_i = Total mass of each fluorinated GHG f emitted from each production or transformation process, annual basis (kg/year, calculated in Equation L–29 of this section).

0.001 = Conversion factor from kg to metric tons.

z = Total number of fluorinated gas production processes, fluorinated gas transformation processes that transform fluorinated gases produced at the facility, or transformation processes that transform fluorinated gases produced at another facility, as appropriate.

(f) *Calculate fluorinated GHG emissions from destruction of fluorinated GHGs that were previously ''produced''.* Estimate annually the total mass of fluorinated GHGs emitted from destruction of fluorinated GHGs that were previously ''produced'' as defined at §98.410(b) using Equation L–31 of this section:

$$E_D = RE_D * (1 - DE) \quad \text{(Eq. L-31)}$$

where:

E_D = The mass of fluorinated GHGs emitted annually from destruction of fluorinated GHGs that were previously ‘‘produced’’ as defined at § 98.410(b) (metric tons).

RE_D = The mass of fluorinated GHGs that were previously ‘‘produced’’ as defined at § 98.410(b) and that are fed annually into the destruction device (metric tons).

DE = Destruction efficiency of the destruction device (fraction).

(g) *Emissions from venting of residual fluorinated GHGs in containers.* If you vent residual fluorinated GHGs from containers, you must either measure the residual fluorinated GHGs vented from each container or develop a heel factor for each combination of fluorinated GHG, container size, and container type that you vent. You do not need to estimate de minimis emissions associated with good-faith attempts to recycle or recover residual fluorinated GHGs in or from containers.

(1) *Measuring contents of each container.* If you weigh or otherwise measure the contents of each container before venting the residual fluorinated GHGs, use Equation L–32 of this section to calculate annual emissions of each fluorinated GHG from venting of residual fluorinated GHG from containers. Convert pressures to masses as directed in paragraph (g)(2)(ii) of this section.

$$E_{Cf} = \sum_{1}^{n} H_{Bfj} - \sum_{1}^{n} H_{Efj} \quad \text{(Eq. L-32)}$$

where:

E_{Cf} = Total mass of each fluorinated GHG f emitted from the facility through venting of residual fluorinated GHG from containers, annual basis (kg/year).

H_{Bfj} = Mass of residual fluorinated GHG f in container j when received by facility.

H_{Efj} = Mass of residual fluorinated GHG f in container j after evacuation by facility. (Facility may equate to zero.)

n = Number of vented containers for each fluorinated GHG f.

(2) *Developing and applying heel factors.* If you use heel factors to estimate emissions of residual fluorinated GHGs vented from containers, you must annually develop these factors based on representative samples of the containers received by your facility from fluorinated GHG users.

(i) *Sample size.* For each combination of fluorinated GHG, container size, and container type that you vent, select a representative sample of containers that reflects the full range of quantities of residual gas returned in that container size and type. This sample must reflect the full range of the industries and a broad range of the customers that use and return the fluorinated GHG, container size, and container type. The minimum sample size for each combination of fluorinated GHG, container size, and container type must be 30, unless this is greater than the number of containers returned within that combination annually, in which case the contents of every container returned must be measured.

(ii) *Measurement of residual gas.* The residual weight or pressure you use for paragraph (g)(1) of this section must be determined by monitoring the mass or the pressure of your cylinders/containers according to § 98.124(k). If you monitor the pressure, convert the pressure to mass using the ideal gas law, as displayed in Equation L–33 of this section, with an appropriately selected Z value.

$$pV=ZnRT \quad \text{(Eq. L-33)}$$

where:

p = Absolute pressure of the gas (Pa)

V = Volume of the gas (m^3)

Z = Compressibility factor

n = Amount of substance of the gas (moles)
R = Gas constant (8.314 Joule/Kelvin mole)
T = Absolute temperature (K)

(iii) *Heel factor calculation.* To determine the heel factor h_{fj} for each combination of fluorinated GHG, container size, and container type, use paragraph (g)(1) of this section to calculate the total heel emissions for each sample selected under paragraph (g)(2)(i) of this section. Divide this total by the number of containers in the sample. Divide the result by the full capacity (the mass of the contents of a full container) of that combination of fluorinated GHG, container size, and container type. The heel factor is expressed as a fraction of the full capacity.

(iv) Calculate annual emissions of each fluorinated GHG from venting of residual fluorinated GHG from containers using Equation L–34 of this section.

$$E_{Cf} = \sum_{j=1}^{n} h_{fj} * N_{fj} * F_{fj} \quad \text{(Eq. L-34)}$$

where:

E_{Cf} = Total mass of each fluorinated GHG f emitted from the facility through venting of residual fluorinated GHG from containers, annual basis (kg/year).
h_{fj} = Facility-wide gas-specific heel factor for fluorinated GHG f (fraction) and container size and type j, as determined in paragraph (g)(2)(iii) of this section.
N_{fj} = Number of containers of size and type j returned to the fluorinated gas production facility.
F_{fj} = Full capacity of containers of size and type j containing fluorinated GHG f (kg).
n = Number of combinations of container sizes and types for fluorinated GHG f.

§98.124 Monitoring and QA/QC requirements.

(a) *Initial scoping speciation to identify fluorinated GHGs.* You must conduct an initial scoping speciation to identify all fluorinated GHGs that may be generated from processes that are subject to this subpart and that have at least one process vent with uncontrolled emissions of 1.0 metric ton or more of fluorinated GHGs per year based on the preliminary estimate of emissions in §98.123(c)(1). You are not required to quantify emissions under this initial scoping speciation. Only fluorinated GHG products and by-products that occur in greater than trace concentrations in at least one stream must be identified under this paragraph.

(1) *Procedure.* To conduct the scoping speciation, select the stream(s) (including process streams or destroyed streams) or process vent(s) that would be expected to individually or collectively contain all of the fluorinated GHG by-products of the process at their maximum concentrations and sample and analyze the contents of these selected streams or process vents. For example, if fluorinated GHG by-products are separated into one low-boiling-point and one high-boiling-point stream, sample and analyze both of these streams. Alternatively, you may sample and analyze streams where fluorinated GHG by-products occur at less than their maximum concentrations, but you must ensure that the sensitivity of the analysis is sufficient to compensate for the expected difference in concentration. For example, if you sample and analyze streams where fluorinated GHG by-products are expected to occur at one half their maximum concentrations elsewhere in the process, you must ensure that the sensitivity of the analysis is sufficient to detect fluorinated GHG by-products that occur at concentrations of 0.05 percent or higher. You do not have to sample and analyze every stream or process vent, i.e., you do not have to sample and analyze a stream or process vent that contains only fluorinated GHGs that are contained in other streams or process vents that are being sampled and analyzed. Sampling and analysis must be conducted according to the procedures in paragraph (e) of this section.

(2) *Previous measurements.* If you have conducted testing of streams (including process streams or destroyed

streams) or process vents less than 10 years before December 31, 2010, and the testing meets the requirements in paragraph (a)(1) of this section, you may use the previous testing to satisfy this requirement.

(b) *Mass balance monitoring.* If you determine fluorinated GHG emissions from any process using the mass balance method under § 98.123(b), you must estimate the total mass of each fluorinated GHG emitted from that process at least monthly. Only streams that contain greater than trace concentrations of fluorine-containing reactants, products, or by-products must be monitored under this paragraph. If you use an element other than fluorine in the mass-balance equation pursuant to § 98.123(b)(3), substitute that element for fluorine in the monitoring requirements of this paragraph.

(1) *Mass measurements.* Measure the following masses on a monthly or more frequent basis using flowmeters, weigh scales, or a combination of volumetric and density measurements with accuracies and precisions that allow the facility to meet the error criteria in § 98.123(b)(1):

(i) Total mass of each fluorine-containing product produced. Account for any used fluorine-containing product added into the production process upstream of the output measurement as directed at § 98.413(b) and § 98.414(b). For each product, the mass produced used for the mass-balance calculation must be the same as the mass produced that is reported under subpart OO of this part, where applicable.

(ii) Total mass of each fluorine-containing reactant fed into the process.

(iii) The mass removed from the process in each stream fed into the destruction device.

(iv) The mass removed from the process in each recaptured stream.

(2) *Concentration measurements for use with § 98.123(b)(4).* If you use § 98.123(b)(4) to estimate the mass of fluorine in destroyed or recaptured streams, measure the following concentrations at least once each calendar month during which the process is operating, on a schedule to ensure that the measurements are representative of the full range of process conditions (e.g., catalyst age). Measure more frequently if this is necessary to meet the error criteria in § 98.123(b)(1). Use equipment and methods (e.g., gas chromatography) that comply with paragraph (e) of this section and that have an accuracy and precision that allow the facility to meet the error criteria in § 98.123(b)(1). Only fluorine-containing reactants, products, and by-products that occur in a stream in greater than trace concentrations must be monitored under this paragraph.

(i) The concentration (mass fraction) of the fluorine-containing product in each stream that is fed into the destruction device.

(ii) The concentration (mass fraction) of each fluorine-containing by-product in each stream that is fed into the destruction device.

(iii) The concentration (mass fraction) of each fluorine-containing reactant in each stream that is fed into the destruction device.

(iv) The concentration (mass fraction) of each fluorine-containing by-product in each stream that is recaptured (c_{Bkl}).

(3) *Concentration measurements for use with § 98.123(b)(15).* If you use § 98.123(b)(15) to estimate the mass of fluorine in destroyed or recaptured streams, measure the concentrations listed in paragraphs (3)(i) and (ii) of this section at least once each calendar month during which the process is operating, on a schedule to ensure that the measurements are representative of the full range of process conditions (e.g., catalyst age). Measure more frequently if this is necessary to meet the error criteria in § 98.123(b)(1). Use equipment and methods (e.g., gas chromatography) that comply with paragraph (e) of this section and that have an accuracy and precision that allow the facility to meet the error criteria in § 98.123(b)(1). Only fluorine-containing reactants, products, and by-products that occur in a stream in greater than trace concentrations must be monitored under this paragraph.

(i) The concentration (mass fraction) of total fluorine in each stream that is fed into the destruction device.

(ii) The concentration (mass fraction) of total fluorine in each stream that is recaptured.

(4) *Emissions characterization: process vents emitting 25,000 metric tons CO_2e or more.* To characterize emissions from any process vent emitting 25,000 metric tons CO_2e or more, comply with paragraphs (b)(4)(i) through (b)(4)(v) of this section, as appropriate. Only fluorine-containing reactants, products, and by-products that occur in a stream in greater than trace concentrations must be monitored under this paragraph.

(i) *Uncontrolled emissions.* If emissions from the process vent are not routed through a destruction device, sample and analyze emissions at the process vent or stack or sample and analyze emitted streams before the process vent. If the process has more than one operating scenario, you must either perform the emission characterization for each operating scenario or perform the emission characterization for the operating scenario that is expected to have the largest emissions and adjust the emission characterization for other scenarios using engineering calculations and assessments as specified in §98.123(c)(4). To perform the characterization, take three samples under conditions that are representative for the operating scenario. Measure the concentration of each fluorine-containing compound in each sample. Use equipment and methods that comply with paragraph (e) of this section. Calculate the average concentration of each fluorine-containing compound across all three samples.

(ii) *Controlled emissions using §98.123(b)(15).* If you use §98.123(b)(15) to estimate the total mass of fluorine in destroyed or recaptured streams, and if the emissions from the process vent are routed through a destruction device, characterize emissions as specified in paragraph (b)(4)(i) of this section before the destruction device. Apply the destruction efficiency demonstrated for each fluorinated GHG in the destroyed stream to that fluorinated GHG. Exclude from the characterization fluorine-containing compounds that are not fluorinated GHGs.

(iii) *Controlled emissions using §98.123(b)(4).* If you use §98.123(b)(4) to estimate the mass of fluorine in destroyed or recaptured streams, and if the emissions from the process vent are routed through a destruction device, characterize the process vent's emissions monthly (or more frequently) using the monthly (or more frequent) measurements under paragraphs (b)(1)(iii) and (b)(2)(i) through (b)(2)(iii) of this section. Apply the destruction efficiency demonstrated for each fluorinated GHG in the destroyed stream to that fluorinated GHG. Exclude from the characterization fluorine-containing compounds that are not fluorinated GHGs.

(iv) *Emissions characterization frequency.* You must repeat emission characterizations performed under paragraph (b)(4)(i) and (b)(4)(ii) of this section under paragraph (b)(4)(iv)(A) or (b)(4)(iv)(B) of this section, whichever occurs first:

(A) *10-year revision.* Repeat the emission characterization every 10 years. In the calculations under §98.123, apply the revised emission characterization to the process activity that occurs after the revision.

(B) *Operating scenario change that affects the emission characterization.* For planned operating scenario changes, you must estimate and compare the emission calculation factors for the changed operating scenario and for the original operating scenario whose process vent specific emission factor was measured. Use the engineering calculations and assessments specified in §98.123(c)(4). If the share of total fluorine-containing compound emissions represented by any fluorinated GHG changes under the changed operating scenario by 15 percent or more of the total, relative to the previous operating scenario (this includes the cumulative change in the emission calculation factor since the last emissions test), you must repeat the emission characterization. Perform the emission characterization before February 28 of the year that immediately follows the change. In the calculations under §98.123, apply the revised emission characterization to the process activity that occurs after the operating scenario change.

(v) *Subsequent measurements.* If a process vent with fluorinated GHG emissions less than 25,000 metric tons CO_2e, per §98.123(c)(2), is later found to have fluorinated GHG emissions of 25,000 metric tons CO_2e or greater, you must perform an emission characterization under this paragraph during the following year.

(5) *Emissions characterization: process vents emitting less than 25,000 metric tons CO_2e.* To characterize emissions from any process vent emitting less than 25,000 metric tons CO_2e, comply with paragraphs (b)(5)(i) through (b)(5)(iii) of this section, as appropriate. Only fluorine-containing reactants, products, and by-products that occur in a stream in greater than trace concentrations must be monitored under this paragraph.

(i) *Uncontrolled emissions.* If emissions from the process vent are not routed through a destruction device, emission measurements must consist of sampling and analysis of emissions at the process vent or stack, sampling and analysis of emitted streams before the process vent, previous test results, provided the tests are representative of current operating conditions of the process, or bench-scale or pilot-scale test data representative of the process operating conditions.

(ii) *Controlled emissions using § 98.123(b)(15).* If you use § 98.123(b)(15) to estimate the total mass of fluorine in destroyed or recaptured streams, and if the emissions from the process vent are routed through a destruction device, characterize emissions as specified in paragraph (b)(5)(i) of this section before the destruction device. Apply the destruction efficiency demonstrated for each fluorinated GHG in the destroyed stream to that fluorinated GHG. Exclude from the characterization fluorine-containing compounds that are not fluorinated GHGs.

(iii) *Controlled emissions using § 98.123(b)(4).* If you use § 98.123(b)(4) to estimate the mass of fluorine in destroyed or recaptured streams, and if the emissions from the process vent are routed through a destruction device, characterize the process vent's emissions monthly (or more frequently) using the monthly (or more frequent) measurements under paragraphs (b)(1)(iii) and (b)(2)(i) through (b)(2)(iii) of this section. Apply the destruction efficiency demonstrated for each fluorinated GHG in the destroyed stream to that fluorinated GHG. Exclude from the characterization fluorine-containing compounds that are not fluorinated GHGs.

(6) *Emissions characterization: emissions not accounted for by process vent estimates.* Calculate the weighted average emission characterization across the process vents before any destruction devices. Apply the weighted average emission characterization for all the process vents to any fluorine emissions that are not accounted for by process vent estimates.

(7) *Impurities in reactants.* If any fluorine-containing impurity is fed into a process along with a reactant (or other input) in greater than trace concentrations, this impurity shall be monitored under this section and included in the calculations under § 98.123 in the same manner as reactants fed into the process, fed into the destruction device, recaptured, or emitted, except the concentration of the impurity in the mass fed into the process shall be measured, and the mass of the impurity fed into the process shall be calculated as the product of the concentration of the impurity and the mass fed into the process. The mass of the reactant fed into the process may be reduced to account for the mass of the impurity.

(8) *Alternative to error calculation.* As an alternative to calculating the relative and absolute errors associated with the estimate of emissions under § 98.123(b), you may comply with the precision, accuracy, measurement and calculation frequency, and fluorinated GHG throughput requirements of paragraph (b)(8)(i) through (b)(8)(iv) of this section.

(i) *Mass measurements.* Measure the masses specified in paragraph (b)(1) of this section using flowmeters, weigh scales, or a combination of volumetric and density measurements with accuracies and precisions of ±0.2 percent of full scale or better.

(ii) *Concentration measurements.* Measure the concentrations specified in paragraph (b)(2) or paragraph (b)(3) of this section, as applicable, using analytical methods with accuracies and precisions of ±10 percent or better.

(iii) *Measurement and calculation frequency.* Perform the mass measurements specified in paragraph (b)(1) of this section and the concentration measurements specified in paragraph (b)(2) or paragraph (b)(3) of this section, as applicable, at least weekly, and calculate emissions at least weekly.

(iv) *Fluorinated-GHG throughput limit.* You may use the alternative to the error calculation specified in paragraph (b)(8) of this section only if the total annual CO_2-equivalent fluorinated GHG throughput of the process is 500,000 $mtCO_2e$ or less. The total throughput is the sum of the masses of the fluorinated GHG reactants, products, and by-products fed into and generated by the process. To convert these masses to CO_2e, use Equation A–1 of § 98.2. For fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part, use a default GWP of 2,000.

(c) *Emission factor testing.* If you determine fluorinated GHG emissions using the site-specific process-vent-specific emission factor, you must meet the requirements in paragraphs (c)(1) through (c)(8) of this section.

(1) *Process vent testing.* Conduct an emissions test that is based on representative performance of the process or operating scenario(s) of the process, as applicable. Include in the emission test any fluorinated greenhouse gas that occurs in more than trace concentrations in the vent stream or, where a destruction device is used, in the inlet to the destruction device. You may include startup and shutdown events if the testing is sufficiently long or comprehensive to ensure that such events are not overrepresented in the emission factor. Malfunction events must not be included in the testing. If you conduct your emission testing after a destruction device, and if the outlet concentration of a fluorinated GHG that is fed into the device is below the detection limit of the method, you may use a concentration of one-half the detection limit to estimate the emission factor.

(2) *Number of runs.* For continuous processes, sample the process vent for a minimum of 3 runs of 1 hour each. If the RSD of the emission factor calculated based on the first 3 runs is greater than or equal to 0.15 for the emission factor, continue to sample the process vent for an additional 3 runs of 1 hour each. If more than one fluorinated GHG is measured, the RSD must be expressed in terms of total CO_2 equivalents. For fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part, use a default GWP of 2,000 in the RSD calculation.

(3) *Process activity measurements.* Determine the mass rate of process feed, process production, or other process activity as applicable during the test using flow meters, weigh scales, or other measurement devices or instruments with an accuracy and precision of ±1 percent of full scale or better. These devices may be the same plant instruments or procedures that are used for accounting purposes (such as weigh hoppers, belt weigh feeders, combination of volume measurements and bulk density, etc.) if these devices or procedures meet the requirement. For monitoring ongoing process activity, use flow meters, weigh scales, or other measurement devices or instruments with an accuracy and precision of ±1 percent of full scale or better.

(4) *Sample each process.* If process vents from separate processes are manifolded together to a common vent or to a common destruction device, you must follow paragraph (c)(4)(i), (c)(4)(ii), or (c)(4)(iii) of this section.

(i) You may sample emissions from each process in the ducts before the emissions are combined.

(ii) You may sample in the common duct or at the outlet of the destruction device when only one process is operating.

(iii) You may sample the combined emissions and use engineering calculations and assessments as specified in § 98.123(c)(4) to allocate the emissions to each manifolded process vent, provided the sum of the calculated fluorinated GHG emissions across the individual process vents is within 20 percent of the total fluorinated GHG emissions measured during the manifolded testing.

(5) *Emission test results.* The results of an emission test must include the analysis of samples, number of test runs, the results of the RSD analysis, the analytical method used, determination of emissions, the process activity, and raw data and must identify the process, the operating scenario, the process vents tested, and the fluorinated GHGs

that were included in the test (i.e., the fluorinated GHGs that occur in more than trace concentrations in the vent stream or, where a destruction device is used, in the inlet to the destruction device, and any other fluorinated GHGs included in the test). The emissions test report must contain all information and data used to derive the process-vent-specific emission factor, as well as key process conditions during the test. Key process conditions include those that are normally monitored for process control purposes and may include but are not limited to yields, pressures, temperatures, etc. (e.g., of reactor vessels, distillation columns).

(7) *Emissions testing frequency.* You must conduct emissions testing to develop the process-vent-specific emission factor under paragraph (c)(7)(i) or (c)(7)(ii) of this section, whichever occurs first:

(i) *10-year revision.* Conduct an emissions test every 10 years. In the calculations under § 98.123, apply the revised process-vent-specific emission factor to the process activity that occurs after the revision.

(ii) *Operating scenario change that affects the emission factor.* For planned operating scenario changes, you must estimate and compare the emission calculation factors for the changed operating scenario and for the original operating scenario whose process vent specific emission factor was measured. Use the calculation methods in § 98.123(c)(4). If the emission calculation factor for the changed operating scenario is 15 percent or more different from the emission calculation factor for the previous operating scenario (this includes the cumulative change in the emission calculation factor since the last emissions test), you must conduct an emissions test to update the process-vent-specific emission factor, unless the difference between the operating scenarios is solely due to the application of a destruction device to emissions under the changed operating scenario. Conduct the test before February 28 of the year that immediately follows the change. In the calculations under § 98.123, apply the revised process-vent-specific emission factor to the process activity that occurs after the operating scenario change.

(8) *Subsequent measurements.* If a continuous process vent with fluorinated GHG emissions less than 10,000 metric tons CO_2e, per § 98.123(c)(2), is later found to have fluorinated GHG emissions of 10,000 metric tons CO_2e or greater, you must conduct the emissions testing for the process vent during the following year and develop the process-vent-specific emission factor from the emissions testing.

(9) *Previous measurements.* If you have conducted an emissions test less than 10 years before December 31, 2010, and the emissions testing meets the requirements in paragraphs (c)(1) through (c)(8) of this section, you may use the previous emissions testing to develop process-vent-specific emission factors. For purposes of paragraph (c)(7)(i) of this section, the date of the previous emissions test rather than December 31, 2010 shall constitute the beginning of the 10-year re-measurement cycle.

(d) *Emission calculation factor monitoring.* If you determine fluorinated GHG emissions using the site-specific process-vent-specific emission calculation factor, you must meet the requirements in paragraphs (d)(1) through (d)(4) of this section.

(1) *Operating scenario.* Perform the emissions calculation for the process vent based on representative performance of the operating scenario of the process. If more than one operating scenario applies to the process that contains the subject process vent, you must conduct a separate emissions calculation for operation under each operating scenario. For each continuous process vent that contains more than trace concentrations of any fluorinated GHG and for each batch process vent that contains more than trace concentrations of any fluorinated GHG, develop the process-vent-specific emission calculation factor for each operating scenario. For continuous process vents, determine the emissions based on the process activity for the representative performance of the operating scenario. For batch process vents, determine emissions based on the process activity for each typical batch operating scenario.

(2) *Process activity measurements.* Use flow meters, weigh scales, or other measurement devices or instruments with an accuracy and precision of ±1 percent of full scale or better for monitoring ongoing process activity.

(3) *Emission calculation results.* The emission calculation must be documented by identifying the process, the operating scenario, and the process vents. The documentation must contain the information and data used to calculate the process-vent-specific emission calculation factor.

(4) *Operating scenario change that affects the emission calculation factor.* For planned operating scenario changes that are expected to change the process-vent-specific emission calculation factor, you must conduct an emissions calculation to update the process-vent-specific emission calculation factor. In the calculations under § 98.123, apply the revised emission calculation factor to the process activity that occurs after the operating scenario change.

(5) *Previous calculations.* If you have performed an emissions calculation for the process vent and operating scenario less than 10 years before December 31, 2010, and the emissions calculation meets the requirements in paragraphs (d)(1) through (d)(4) of this section and in § 98.123(c)(4)(i) and (c)(4)(ii), you may use the previous calculation to develop the site-specific process-vent-specific emission calculation factor.

(e) *Emission and stream testing, including analytical methods.* Select and document testing and analytical methods as follows:

(1) *Sampling and mass measurement for emission testing.* For emission testing in process vents or at the stack, use methods for sampling, measuring volumetric flow rates, non-fluorinated-GHG gas analysis, and measuring stack gas moisture that have been validated using a scientifically sound validation protocol.

(i) Sample and velocity traverses. Acceptable methods include but are not limited to EPA Method 1 or 1A in Appendix A–1 of 40 CFR part 60.

(ii) Velocity and volumetric flow rates. Acceptable methods include but are not limited to EPA Method 2, 2A, 2B, 2C, 2D, 2F, or 2G in Appendix A–1 of 40 CFR part 60. Alternatives that may be used for determining flow rates include OTM–24 (incorporated by reference, see § 98.7) and ALT–012 (incorporated by reference, see § 98.7).

(iii) Non-fluorinated-GHG gas analysis. Acceptable methods include but are not limited to EPA Method 3, 3A, or 3B in Appendix A–1 of 40 CFR part 60.

(iv) Stack gas moisture. Acceptable methods include but are not limited to EPA Method 4 in Appendix A–1 of 40 CFR part 60.

(2) *Analytical methods.* Use a quality-assured analytical measurement technology capable of detecting the analyte of interest at the concentration of interest and use a sampling and analytical procedure validated with the analyte of interest at the concentration of interest. Where calibration standards for the analyte are not available, a chemically similar surrogate may be used. Acceptable analytical measurement technologies include but are not limited to gas chromatography (GC) with an appropriate detector, infrared (IR), fourier transform infrared (FTIR), and nuclear magnetic resonance (NMR). Acceptable methods for determining fluorinated GHGs include EPA Method 18 in appendix A–1 of 40 CFR part 60, EPA Method 320 in appendix A of 40 CFR part 63, EPA 430–R–10–003 (incorporated by reference, see § 98.7), ASTM D6348–03 (incorporated by reference, see § 98.7), or other analytical methods validated using EPA Method 301 at 40 CFR part 63, appendix A or some other scientifically sound validation protocol. Acceptable methods for determining total fluorine concentrations for fluorine-containing compounds in streams under paragraph (b)(3) of this section include ASTM D7359–08 (incorporated by reference, see § 98.7), or other analytical methods validated using EPA Method 301 at 40 CFR part 63, appendix A or some other scientifically sound validation protocol. The validation protocol may include analytical technology manufacturer specifications or recommendations.

(3) *Documentation in GHG Monitoring Plan.* Describe the sampling, measurement, and analytical method(s) used under paragraphs (e)(1) and (e)(2) of this section in the GHG Monitoring

Plan as required under § 98.3(g)(5). Identify the methods used to obtain the samples and measurements listed under paragraphs (e)(1)(i) through (e)(1)(iv) of this section. At a minimum, include in the description of the analytical method a description of the analytical measurement equipment and procedures, quantitative estimates of the method's accuracy and precision for the analytes of interest at the concentrations of interest, as well as a description of how these accuracies and precisions were estimated, including the validation protocol used.

(f) *Emission monitoring for pieces of equipment.* If you conduct a site-specific leak detection method or monitoring approach for pieces of equipment, follow paragraph (f)(1) or (f)(2) of this section and follow paragraph (f)(3) of this section.

(1) *Site-specific leak monitoring approach.* You may develop a site-specific leak monitoring approach. You must validate the leak monitoring method and describe the method and the validation in the GHG Monitoring Plan. To validate the site-specific method, you may, for example, release a known rate of the fluorinated GHGs or surrogates of interest, or you may compare the results of the site-specific method to those of a method that has been validated for the fluorinated GHGs or surrogates of interest. In the description of the leak detection method and its validation, include a detailed description of the method, including the procedures and equipment used and any sampling strategies. Also include the rationale behind the method, including why the method is expected to result in an unbiased estimate of emissions from equipment leaks. If the method is based on methods that are used to detect or quantify leaks or other emissions in other regulations, standards, or guidelines, identify and describe the regulations, standards, or guidelines and why their methods are applicable to emissions of fluorinated GHGs or surrogates from leaks. Account for possible sources of error in the method, e.g., instrument detection limits, measurement biases, and sampling biases. Describe validation efforts, including but not limited to any comparisons against standard leaks or concentrations, any comparisons against other methods, and their results. If you use the Screening Ranges Approach, the EPA Correlation Approach, or the Unit-Specific Correlation Approach with a monitoring instrument that does not meet all of the specifications in EPA Method 21 at 40 CFR part 60, appendix A–7, then explain how and why the monitoring instrument, as used at your facility, would nevertheless be expected to accurately detect and quantify emissions of fluorinated GHGs or surrogates from process equipment, and describe how you verified its accuracy. For all methods, provide a quantitative estimate of the accuracy and precision of the method.

(2) *EPA Method 21 monitoring.* If you determine that EPA Method 21 at 40 CFR part 60, appendix A–7 is appropriate for monitoring a fluorinated GHG, conduct the screening value concentration measurements using EPA Method 21 at 40 CFR part 60, appendix A–7 to determine the screening range data or the actual screening value data for the Screening Ranges Approach, EPA Correlation Approach, or the Unit-Specific Correlation Approach. For the one-time testing to develop the Unit-Specific Correlation equations in EPA–453/R–95–017 (incorporated by reference, see § 98.7), conduct the screening value concentration measurements using EPA Method 21 at 40 CFR part 60, appendix A–7 and the bagging procedures to measure mass emissions. Concentration measurements of bagged samples must be conducted using gas chromatography following EPA Method 18 analytical procedures or other method according to § 98.124(e). Use methane or other appropriate compound as the calibration gas.

(3) *Frequency of measurement and sampling.* If you estimate emissions based on monitoring of equipment, conduct monitoring at least annually. Sample at least one-third of equipment annually (except for equipment that is unsafe-to-monitor, difficult-to-monitor, insulated, or in heavy liquid service, pumps with dual mechanical seals, agitators with dual mechanical seals, pumps with no external shaft, agitators with no external shaft, pressure relief devices in gas and vapor service

with an upstream rupture disk, sampling connection systems with closed-loop or closed purge systems, and pieces of equipment whose leaks are routed through a closed vent system to a destruction device), changing the sample each year such that at the end of three years, all equipment in the process has been monitored. If you estimate emissions based on a sample of the equipment in the process, ensure that the sample is representative of the equipment in the process. If you have multiple processes that have similar types of equipment in similar service, and that produce or transform similar fluorinated GHGs (in terms of chemical composition, molecular weight, and vapor pressure) at similar pressures and concentrations, then you may annually sample all of the equipment in one third of these processes rather than one third of the equipment in each process.

(g) *Destruction device performance testing.* If you vent or otherwise feed fluorinated GHGs into a destruction device and apply the destruction efficiency of the device to one or more fluorinated GHGs in § 98.123, you must conduct emissions testing to determine the destruction efficiency for each fluorinated GHG to which you apply the destruction efficiency. You must either determine the destruction efficiency for the most-difficult-to-destroy fluorinated GHG fed into the device (or a surrogate that is still more difficult to destroy) and apply that destruction efficiency to all the fluorinated GHGs fed into the device or alternatively determine different destruction efficiencies for different groups of fluorinated GHGs using the most-difficult-to-destroy fluorinated GHG of each group (or a surrogate that is still more difficult to destroy).

(1) *Destruction efficiency testing.* You must sample the inlet and outlet of the destruction device for a minimum of three runs of 1 hour each to determine the destruction efficiency. You must conduct the emissions testing using the methods in paragraph (e) of this section. To determine the destruction efficiency, emission testing must be conducted when operating at high loads reasonably expected to occur (i.e., representative of high total fluorinated GHG load that will be sent to the device) and when destroying the most-difficult-to-destroy fluorinated GHG (or a surrogate that is still more difficult to destroy) that is fed into the device from the processes subject to this subpart or that belongs to the group of fluorinated GHGs for which you wish to establish a DE. If the outlet concentration of a fluorinated GHG that is fed into the device is below the detection limit of the method, you may use a concentration of one-half the detection limit to estimate the destruction efficiency.

(i) If perfluoromethane (CF_4) is vented to the destruction device in any stream in more than trace concentrations, you must test and determine the destruction efficiency achieved specifically for CF_4 to take credit for the CF_4 emissions reduction.

(ii) If sulfur hexafluoride (SF_6) is vented to the destruction device in any stream in more than trace concentrations, you must test and determine the destruction efficiency achieved specifically for SF_6, or alternatively for CF_4 as a surrogate, to take credit for the SF_6 emissions reduction.

(iii) If saturated perfluorocarbons other than CF_4 are vented to the destruction device in any stream in more than trace concentrations, you must test and determine the destruction efficiency achieved for the lowest molecular weight saturated perfluorocarbon vented to the destruction device, or alternatively for a lower molecular weight saturated PFC or SF_6 as a surrogate, to take credit for the PFC emission reduction.

(iv) For all other fluorinated GHGs that are vented to the destruction device in any stream in more than trace concentrations, you must test and determine the destruction efficiency achieved for the most-difficult-to-destroy fluorinated GHG or surrogate vented to the destruction device. Examples of acceptable surrogates include the Class 1 compounds (ranked 1 through 34) in Appendix D, Table D–1 of ‘‘Guidance on Setting Permit Conditions and Reporting Trial Burn Results; Volume II of the Hazardous Waste Incineration Guidance Series,’’ January 1989, EPA Publication EPA 625/6–89/019. You can obtain a copy of this publication by contacting the Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, (202) 272–0167, *http://www.epa.gov*.

(2) *Destruction efficiency testing frequency*. You must conduct emissions testing to determine the destruction efficiency as provided in paragraphs (g)(2)(i) or (ii) of this section, whichever occurs first:

(i) Conduct an emissions test every 10 years. In the calculations under § 98.123, apply the updated destruction efficiency to the destruction that occurs after the test.

(ii) *Destruction device changes that affect the destruction efficiency*. If you make a change to the destruction device that would be expected to affect the destruction efficiency, you must conduct an emissions test to update the destruction efficiency. Conduct the test before the February 28 of the year that immediately follows the change. In the calculations under § 98.123, apply the updated destruction efficiency to the destruction that occurs after the change to the device.

(3) *Previous testing* .If you have conducted an emissions test within the 10 years prior to December 31, 2010, and the emissions testing meets the requirements in paragraph (g)(1) of this section, you may use the destruction efficiency determined during this previous emissions testing. For purposes of paragraph (g)(2)(i) of this section, the date of the previous emissions test rather than December 31, 2010 shall constitute the beginning of the 10-year re-measurement cycle.

(4) *Hazardous Waste Combustor testing*. If a destruction device used to destroy fluorinated GHG is subject to subpart EEE of part 63 of this chapter or any portion of parts 260–270 of this chapter, you may apply the destruction efficiency specifically determined for CF_4, SF_6, PFCs other than CF_4, and all other fluorinated GHGs under that test if the testing meets the criteria in paragraph (g)(1)(i) through (g)(1)(iv) of this section. If the testing of the destruction efficiency under subpart EEE of part 63 of this chapter was conducted more than 10 years ago, you may use the most recent destruction efficiency test provided that the design, operation, or maintenance of the destruction device has not changed since the last destruction efficiency test in a manner that could affect the ability to achieve the destruction efficiency, and the hazardous waste is fed into the normal flame zone.

(h) *Mass of previously produced fluorinated GHGs fed into destruction device*. You must measure the mass of each fluorinated GHG that is fed into the destruction device in more than trace concentrations and that was previously produced as defined at § 98.410(b). Such fluorinated GHGs include but are not limited to quantities that are shipped to the facility by another facility for destruction and quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed. You must use flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of ±1 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the fluorinated GHG being destroyed, you must measure the concentration of the fluorinated GHG being destroyed. You must multiply this concentration (mass fraction) by the mass measurement to obtain the mass of the fluorinated GHG fed into the destruction device.

(i) *Emissions due to malfunctions of destruction device*. In their estimates of the mass of fluorinated GHG destroyed, fluorinated gas production facilities that destroy fluorinated GHGs must account for any temporary reductions in the destruction efficiency that result from any malfunctions of the destruction device, including periods of operation outside of the operating conditions defined in operating permit requirements and/or destruction device manufacturer specifications.

(j) *Emissions due to process startup, shutdown, or malfunctions*. Fluorinated GHG production facilities must account for fluorinated GHG emissions that occur as a result of startups, shutdowns, and malfunctions, either recording fluorinated GHG emissions during these events, or documenting that these events do not result in significant fluorinated GHG emissions.

Facilities may use the calculation methods in § 98.123(c)(1) to estimate emissions during startups, shutdowns, and malfunctions.

(k) *Monitoring for venting residual fluorinated GHG in containers.* Measure the residual fluorinated GHG in containers received by the facility either using scales or using pressure and temperature measurements. You may use pressure and temperature measurements only in cases where no liquid fluorinated GHG is present in the container. Scales must have an accuracy and precision of ±1 percent or better of the filled weight (gas plus tare) of the containers of fluorinated GHGs that are typically weighed on the scale. For example, for scales that are generally used to weigh cylinders that contain 115 pounds of gas when full and that have a tare weight of 115 pounds, this equates to ±1 percent of 230 pounds, or ±2.3 pounds. Pressure gauges and thermometers used to measure quantities that are monitored under this paragraph must have an accuracy and precision of ±1 percent of full scale or better.

(l) Initial scoping speciations, emissions testing, emission factor development, emission calculation factor development, emission characterization development, and destruction efficiency determinations must be completed by February 29, 2012 for processes and operating scenarios that operate between December 31, 2010 and December 31, 2011. For other processes and operating scenarios, initial scoping speciations, emissions testing, emission factor development, emission calculation factor development, emission characterization development, and destruction efficiency determinations must be complete by February 28 of the year following the year in which the process or operating scenario commences or recommences.

(m) Calibrate all flow meters, weigh scales, and combinations of volumetric and density measures using monitoring instruments traceable to the International System of Units (SI) through the National Institute of Standards and Technology (NIST) or other recognized national measurement institute. Recalibrate all flow meters, weigh scales, and combinations of volumetric and density measures at the minimum frequency specified by the manufacturer. Use any of the following applicable flow meter test methods or the calibration procedures specified by the flow meter, weigh-scale, or other volumetric or density measure manufacturer.

(1) ASME MFC–3M–2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, see § 98.7).

(2) ASME MFC–4M–1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters (incorporated by reference, see § 98.7).

(3) ASME–MFC–5M–1985, (Reaffirmed 1994) Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters (incorporated by reference, see § 98.7).

(4) ASME MFC–6M–1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, see § 98.7).

(5) ASME MFC–7M–1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, see § 98.7).

(6) ASME MFC–9M–1988 (Reaffirmed 2001) Measurement of Liquid Flow in Closed Conduits by Weighing Method (incorporated by reference, see § 98.7).

(7) ASME MFC–11M–2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters (incorporated by reference, see § 98.7).

(8) ASME MFC–14M–2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, see § 98.7).

(n) All analytical equipment used to determine the concentration of fluorinated GHGs, including but not limited to gas chromatographs and associated detectors, infrared (IR), fourier transform infrared (FTIR), and nuclear magnetic resonance (NMR) devices, must be calibrated at a frequency needed to support the type of analysis specified in the GHG Monitoring Plan as required under § 98.124(e)(3) and 93.3(g)(5). Quality assurance samples at the concentrations of concern must be used for the calibration. Such quality assurance samples must consist of or be prepared from certified standards of the analytes of concern where available; if not available, calibration must be performed by a method specified in the GHG Monitoring Plan.

(o) Special provisions for estimating 2011 and subsequent year emissions.

(1) *Best available monitoring methods.* To estimate emissions that occur from January 1, 2011 through June 30, 2011, owners or operators may use best available monitoring methods for any parameter that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart. The owner or operator must use the calculation methodologies and equations in § 98.123, but may use the best available monitoring method for any parameter for which it is not reasonably feasible to acquire, install, or operate a required piece of monitoring equipment, to procure measurement services from necessary providers, or to gain physical access to make required measurements in a facility by January 1, 2011. Starting no later than July 1, 2011, the owner or operator must discontinue using best available methods and begin following all applicable monitoring and QA/QC requirements of this part, except as provided in paragraphs (o)(2) through (o)(4) of this section. Best available monitoring methods means any of the following methods specified in this paragraph:

(i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart.

(ii) Supplier data.

(iii) Engineering calculations or assessments.

(iv) Other company records.

(2) *Requests for extension of the use of best available monitoring methods to estimate 2011 emissions: parameters other than scoping speciations, emission factors, and emission characterizations.* The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods for parameters other than scoping speciations, emission factors, or emission characterizations to estimate emissions that occur between July 1, 2011 and December 31, 2011.

(i) *Timing of request.* The extension request must be submitted to EPA no later than February 28, 2011.

(ii) *Content of request.* Requests must contain the following information:

(A) A list of specific items of monitoring equipment and measurement services for which the request is being made and the locations (e.g., processes and vents) where each piece of monitoring equipment will be installed and where each measurement service will be provided.

(B) Identification of the specific rule requirements for which the monitoring equipment or measurement service is needed.

(C) A description of the reasons why the needed equipment could not be obtained, installed, or operated or why the needed measurement service could not be provided before July 1, 2011. The owner or operator must consider all of the data collection and emission calculation options outlined in the rule for a specific emissions source before claiming that a specific safety, technical, logistical, or legal barrier exists.

(D) If the reason for the extension is that the equipment cannot be purchased, delivered, or installed before July 1, 2011, include supporting documentation such as the date the monitoring equipment was ordered, investigation of alternative suppliers, the dates by which alternative vendors promised delivery or installation, backorder notices or unexpected delays, descriptions of actions taken to expedite delivery or installation, and the current expected date of delivery or installation.

(E) If the reason for the extension is that service providers were unable to provide necessary measurement services, include supporting documentation demonstrating that these services could not be acquired before July 1, 2011. This documentation must include written correspondence to and from at least two service providers stating that they will not be able to provide the necessary services before July 1, 2011.

(F) If the reason for the extension is that the process is operating continuously without process shutdown, include supporting documentation showing that it is not practicable to isolate the process equipment or unit and install the measurement device without a full shutdown or a hot tap, and that there is no opportunity before July 1, 2011 to install the device. Include the date of the three most recent shutdowns for each relevant process equipment or unit, the frequency of shutdowns for each relevant process equipment or unit, and the date of the next planned process equipment or unit shutdown.

(G) If the reason for the extension is that access to process streams, emissions streams, or destroyed streams, as applicable, could not be gained before July 1, 2011 for reasons other than the continuous operation of the process without shutdown, include illustrative documentation such as photographs and engineering diagrams demonstrating that access could not be gained.

(H) A description of the best available monitoring methods that will be used and how their results will be applied (i.e., which calculation method will be used) to develop the emission estimate. Where the proposed best available monitoring method is the use of current monitoring data in the mass-balance approach, include the estimated relative and absolute errors of the mass-balance approach using the current monitoring data.

(I) A description of the specific actions the owner or operator will take to comply with monitoring requirements by January 1, 2012.

(3) *Requests for extension of the use of best available monitoring methods to estimate 2011 emissions: scoping speciations, emission factors, and emission characterizations.* The owner or operator may submit a request to the Administrator to use one or more best available monitoring methods for scoping speciations, emission factors, and emission characterizations to estimate emissions that occur between July 1, 2011 and December 31, 2011.

(i) *Timing of request.* The extension request must be submitted to EPA no later than June 30, 2011.

(ii) *Content of request.* Requests must contain the information outlined in paragraph (o)(2)(ii) of this section, substituting March 1, 2012 for July 1, 2011 and substituting March 1, 2013 for January 1, 2012.

(iii) *Reporting of 2011 emissions using scoping speciations, emission factors, and emission characterizations developed after February 29, 2012.* Facilities that are approved to use best available monitoring methods in 2011 for scoping speciations, emission factors, or emission characterizations for certain processes must submit, by March 31, 2013, revised 2011 emission estimates that reflect the scoping speciations, emission factors, and emission characterizations that are measured for those processes after February 29, 2012. If the operating scenario for 2011 is different from all of the operating scenarios for which emission factors are developed after February 29, 2012, use Equation L–23 at §98.123(c)(3)(viii) to adjust the emission factor(s) or emission characterizations measured for the post-February 29, 2012 operating scenario(s) to account for the differences.

(4) *Requests for extension of the use of best available monitoring methods to estimate emissions that occur after 2011.* EPA does not anticipate approving the use of best available monitoring methods to estimate emissions that occur beyond December 31, 2011; however, EPA reserves the right to review requests for unique and extreme circumstances which include safety, technical infeasibility, or inconsistency with other local, State or Federal regulations.

(i) *Timing of request.* The extension request must be submitted to EPA no later than June 30, 2011.

(ii) *Content of request.* Requests must contain the following information:

(A) The information outlined in paragraph (o)(2)(ii) of this section. For scoping speciations, emission factors, and emission characterizations, substitute March 1, 2013 for July 1, 2011 and substitute March 1, 2014 for January 1, 2012. For other parameters, substitute January 1, 2012 for July 1, 2011 and substitute January 1, 2013 for January 1, 2012.

(B) A detailed outline of the unique circumstances necessitating an extension, including specific data collection issues that do not meet safety regulations, technical infeasibility or specific laws or regulations that conflict with data collection. The owner or operator must consider all the data collection and emission calculation options outlined in the rule for a specific emissions source before claiming that a specific safety, technical or legal barrier exists.

(C) A detailed explanation and supporting documentation of how and when the owner or operator will receive the required data and/or services to comply with the reporting requirements of this subpart in the future.

(E) The Administrator reserves the right to require that the owner or operator provide additional documentation.

(iii) *Reporting of 2011 and subsequent year emissions using scoping speciations, emission factors, and emission characterizations developed after approval to use best available monitoring methods expires.* Facilities that are approved to use best available monitoring methods in 2011 and subsequent years for scoping speciations, emission factors, or emission characterizations for certain processes must submit, by March 31 of the year that begins one year after their approval to use best available monitoring method(s) expires, revised emission estimates for 2011 and subsequent years that reflect the scoping speciations, emission factors, and emission characterizations that are measured for those processes in 2013 or subsequent years. If the operating scenario for 2011 or subsequent years is different from all of the operating scenarios for which emission factors or emission characterizations are developed in 2013 or subsequent years, use Equation L–23 of §98.123(c)(3)(viii) to adjust the emission factor(s) or emission characterization(s) measured for the new operating scenario(s) to account for the differences.

(5) *Approval criteria.* To obtain approval, the owner or operator must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, or operate the required piece of monitoring equipment, to procure measurement services from necessary providers, or to gain physical access to make required measurements in a facility according to the requirements of this subpart by the dates specified in paragraphs (o)(2), (3), and (4) of this section for any of the reasons described in paragraph (o)(2)(ii) of this section, or, for requests under paragraph (o)(4) of this section, any of the reasons described in paragraph (o)(4)(ii)(B) of this section.

§ 98.125 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations in §98.123 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter must be used in the calculations as specified in the paragraphs (b) and (c) of this section. You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of the fluorinated GHG concentration or fluorine-containing compound concentration, the substitute data value must be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident.

(c) For each missing value of the mass produced, fed into the production process, fed into the transformation process, or fed into destruction devices, the substitute value of that parameter must be a secondary mass measurement where such a measurement is available. For example, if the mass produced is usually measured with a flowmeter at the inlet to the day tank and that flowmeter fails to meet an accuracy or precision test, malfunctions, or is rendered inoperable, then the mass produced may be estimated by calculating the change in volume in the day tank and multiplying it by the density of the product. Where a secondary mass measurement is not available, the substitute value of the parameter must be an estimate based on a related parameter. For example, if a flowmeter measuring the mass fed into a destruction device is rendered inoperable, then the mass fed into the destruction device may be estimated using the production rate and the previously observed relationship between the production rate and the mass flow rate into the destruction device.

§ 98.126 Data reporting requirements.

(a) *All facilities.* In addition to the information required by §98.3(c), you must report the information in paragraphs (a)(2) through (a)(6) of this section according to the schedule in paragraph (a)(1) of this section, except as otherwise provided in paragraph (j) of this section or in § 98.3(c)(4)(vii) and Table A–7 of Subpart A of this part.

(1) *Frequency of reporting under paragraph (a) of this section.* The information in paragraphs (a)(2), (5), and (6) of this section must be reported annually. The information in paragraphs (a)(3) and (4) of this section must be reported once by March 31, 2012 for each process and operating scenarios that operates between December 31, 2010 and December 31, 2011. For other processes and operating scenarios, the information in paragraphs (a)(3) and (4) of this section must be reported once by March 31 of the year following the year in which the process or operating scenario commences or recommences.

(2) You must report the total mass in metric tons of each fluorinated GHG emitted from:

(i) Each fluorinated gas production process and all fluorinated gas production processes combined.

(ii) Each fluorinated gas transformation process that is not part of a fluorinated gas production process and all such fluorinated gas transformation processes combined, except report separately fluorinated GHG emissions from transformation processes where a fluorinated GHG reactant is produced at another facility.

(iii) Each fluorinated gas destruction process that is not part of a fluorinated gas production process or a fluorinated gas transformation process and all such fluorinated gas destruction processes combined.

(iv) Venting of residual fluorinated GHGs from containers returned from the field.

(3) The chemical identities of the contents of the stream(s) (including process, emissions, and destroyed streams) analyzed under the initial scoping speciation of fluorinated GHG at § 98.124(a), by process.

(4) The location and function of the stream(s) (including process streams, emissions streams, and destroyed streams) that were analyzed under the initial scoping speciation of fluorinated GHG at § 98.124(a), by process.

(5) The methods used to determine the mass emissions of each fluorinated GHG, i.e., mass balance, process-vent-specific emission factor, or process-vent-specific emission calculation factor, at the facility. If you use the process-vent-specific emission factor or process-vent-specific emission calculation factor method, report the methods used to estimate emissions from equipment leaks.

(6) The chemical formula and total mass produced of the fluorinated gas product in metric tons, by chemical and process.

(b) *Reporting for mass balance approach.* For processes whose emissions are determined using the mass-balance approach under § 98.123(b), you must report the information listed in paragraphs (b)(1) through (b)(13) of this section for each process on an annual basis. Identify and separately report fluorinated GHG emissions from transformation processes where the fluorinated GHG reactants are produced at another facility. If you use an element other than fluorine in the mass-balance equation pursuant to § 98.123(b)(3), substitute that element for fluorine in the reporting requirements of this paragraph.

(1) If you calculate the relative and absolute errors under 98.123(b)(1), the absolute and relative errors calculated under paragraph § 98.123(b)(1), as well as the data (including quantities and their accuracies and precisions) used in these calculations.

(2) The balanced chemical equation that describes the reaction used to manufacture the fluorinated GHG product and each fluorinated GHG transformation product.

(3) The mass and chemical formula of each fluorinated GHG reactant emitted from the process in metric tons.

(4) The mass and chemical formula of the fluorinated GHG product emitted from the process in metric tons.

(5) The mass and chemical formula of each fluorinated GHG by-product emitted from the process in metric tons.

(6) The mass and chemical formula of each fluorine-containing reactant that is fed into the process (metric tons).

(7) The mass and chemical formula of each fluorine-containing product produced by the process (metric tons).

(8) If you use § 98.123(b)(4) to estimate the total mass of fluorine in destroyed or recaptured streams, report the following.

(i) The mass and chemical formula of each fluorine-containing product that is removed from the process and fed into the destruction device (metric tons).

(ii) The mass and chemical formula of each fluorine-containing by-product that is removed from the process and fed into the destruction device (metric tons).

(iii) The mass and chemical formula of each fluorine-containing reactant that is removed from the process and fed into the destruction device (metric tons).

(iv) The mass and chemical formula of each fluorine-containing by-product that is removed from the process and recaptured (metric tons).

(v) The demonstrated destruction efficiency of the destruction device for each fluorinated GHG fed into the device from the process in greater than trace concentrations (fraction).

(9) If you use § 98.123(b)(15) to estimate the total mass of fluorine in destroyed or recaptured streams, report the following.

(i) The mass of fluorine in each stream that is fed into the destruction device (metric tons).

(ii) The mass of fluorine that is recaptured (metric tons).

(iii) The weighted average destruction efficiency of the destruction device calculated for each stream under § 98.123(b)(16).

(10) The fraction of the mass emitted that consists of each fluorine-containing reactant.

(11) The fraction of the mass emitted that consists of the fluorine-containing product.

(12) The fraction of the mass emitted that consists of each fluorine-containing by-product.

(13) The method used to estimate the total mass of fluorine in destroyed or recaptured streams (specify § 98.123(b)(4) or (15)).

(c) *Reporting for emission factor and emission calculation factor approach.* For processes whose emissions are determined using the emission factor approach under § 98.123(c)(3) or the emission calculation factor under § 98.123(c)(4), you must report the following for each process. Fluorinated GHG emissions from transformation processes where the fluorinated GHG reactants are produced at another facility must be identified and reported separately from other fluorinated GHG emissions.

(1) The identity and quantity of the process activity used to estimate emissions (e.g., tons of product produced or tons of reactant consumed).

(2) The site-specific, process-vent-specific emission factor(s) or emission calculation factor for each process vent.

(3) The mass of each fluorinated GHG emitted from each process vent (metric tons).

(4) The mass of each fluorinated GHG emitted from equipment leaks (metric tons).

(d) *Reporting for missing data.* Where missing data have been estimated pursuant to § 98.125, you must report the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data.

(e) *Reporting of destruction device excess emissions data.* Each fluorinated gas production facility that destroys fluorinated GHGs must report the excess emissions that result from malfunctions of the destruction device, and these excess emissions would be reflected in the fluorinated GHG estimates in § 98.123(b) and (c). Such excess emissions would occur if the destruction efficiency was reduced due to the malfunction.

(f) *Reporting of destruction device testing.* By March 31, 2012 or by March 31 of the year immediately following the year in which it begins fluorinated GHG destruction, each fluorinated gas production facility that destroys fluorinated GHGs must submit a report containing the information in paragraphs (f)(1) through (f)(4) of this section. This report is one-time unless you make a change to the destruction device that would be expected to affect its destruction efficiencies.

(1) Destruction efficiency (DE) of each destruction device for each fluorinated GHG whose destruction the facility reflects in § 98.123, in accordance with § 98.124(g)(1)(i) through (iv).

(2) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine destruction efficiency, including surrogates, and information on why the surrogate is sufficient to demonstrate the destruction efficiency for each fluorinated GHG, consistent with requirements in § 98.124(g)(1), vented to the destruction device.

(3) Date of the most recent destruction device test.

(4) Name of all applicable Federal or State regulations that may apply to the destruction process.

(5) If you make a change to the destruction device that would be expected to affect its destruction efficiencies, submit a revised report that reflects the changes, including the revised destruction efficiencies measured for the device under § 98.124(g)(2)(ii), by March 31 of the year that immediately follows the change.

(g) *Reporting for destruction of previously produced fluorinated GHGs.* Each fluorinated gas production facility that destroys fluorinated GHGs must report, separately from the fluorinated GHG emissions reported under paragraphs (b) or (c) of this section, the following for each previously produced fluorinated GHG destroyed:

(1) The mass of the fluorinated GHG fed into the destruction device.

(2) The mass of the fluorinated GHG emitted from the destruction device.

(h) *Reporting of emissions from venting of residual fluorinated GHGs from containers.* Each fluorinated gas production facility that vents residual fluorinated GHGs from containers must report the following for each fluorinated GHG vented:

(1) The mass of the residual fluorinated GHG vented from each container size and type annually (tons).

(2) If applicable, the heel factor calculated for each container size and type.

(i) *Reporting of fluorinated GHG products of incomplete combustion (PICs) of fluorinated gases.* Each fluorinated gas production facility that destroys fluorinated gases must submit a one-time report by June 30, 2011, that describes any measurements, research, or analysis that it has performed or obtained that relate to the formation of products of incomplete combustion that are fluorinated GHGs during the destruction of fluorinated gases. The report must include the methods and results of any measurement or modeling studies, including the products of incomplete combustion for which the exhaust stream was analyzed, as well as copies of relevant scientific papers, if available, or citations of the papers, if they are not. No new testing is required to fulfill this requirement.

(j) *Special provisions for reporting years 2011, 2012, and 2013 only.* For reporting years 2011, 2012, and 2013, the owner or operator of a facility must comply with paragraphs (j)(1), (j)(2), and (j)(3) of this section.

(1) *Timing.* The owner or operator of a facility is not required to report the data elements at § 98.3(c)(4)(iii) and paragraphs (a)(2), (a)(3), (a)(4), (a)(6), (b), (c), (d), (e), (f), (g), and (h) of this section until the later of March 31, 2015 or the date set forth for that data element at § 98.3(c)(4)(vii) and Table A–7 of Subpart A of this part.

(2) *Excess emissions.* Excess emissions of fluorinated GHGs resulting from destruction device malfunctions must be reflected in the reported facility-wide CO_2e emissions but are not required to be reported separately.

(3) *Calculation and reporting of CO_2e.* You must report the total fluorinated GHG emissions covered by this subpart, expressed in metric tons of CO_2e. This includes emissions from all fluorinated gas production processes, all fluorinated gas transformation processes that are not part of a fluorinated gas production process, all fluorinated gas destruction processes that are not part of a fluorinated gas production process or a fluorinated gas transformation process, and venting of residual fluorinated GHGs from containers returned from the field. To convert fluorinated GHG emissions to CO_2e for reporting under this section, use Equation A–1 of § 98.2. For fluorinated GHGs whose GWPs are not listed in Table A–1 of Subpart A of this part, use either the default GWP specified below

or your best estimate of the GWP based on the information described in § 98.123(c)(1)(vi)(A)(*3*). Use of quantitative structure activity relationships (QSARs) is an acceptable method for determining GWPs in situations where pure standards of the "target" fluorinated GHG are not available, the "target" fluorinated GHG cannot be isolated from gas streams, and FTIR spectra for the impurities are not available.

(i) If you choose to use a default GWP rather than your best estimate of the GWP for fluorinated GHGs whose GWPs are not listed in Table A–1 of Subpart A of this part, use a default GWP of 10,000 for fluorinated GHGs that are fully fluorinated GHGs and use a default GWP of 2000 for other fluorinated GHGs.

(ii) Provide the total annual emissions across fluorinated GHGs for the entire facility, in metric tons of CO_2e, that were calculated using the default GWP of 2000.

(iii) Provide the total annual emissions across fluorinated GHGs for the entire facility, in metric tons of CO_2e, that were calculated using the default GWP of 10,000.

(iv) Provide the total annual emissions across fluorinated GHGs for the entire facility, in metric tons of CO_2e, that were calculated using your best estimate of the GWP.

[75 FR 74831, Dec. 1, 2010, as amended at 77 FR 51489, Aug. 24, 2012; 78 FR 71954, Nov. 29, 2013]

§ 98.127 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the dated records specified in paragraphs (a) through (k) of this section, as applicable.

(a) *Process information records.* (1) Identify all products and processes subject to this subpart. Include the unit identification as appropriate.

(2) Monthly and annual records, as applicable, of all analyses and calculations conducted as required under § 98.123, including the data monitored under § 98.124, and all information reported as required and § 98.126.

(b) *Scoping speciation.* Retain records documenting the information reported under § 98.126(a)(3) and (4).

(c) *Mass-balance method.* Retain the following records for each process for which the mass-balance method was used to estimate emissions. If you use an element other than fluorine in the mass-balance equation pursuant to § 98.123(b)(3), substitute that element for fluorine in the recordkeeping requirements of this paragraph.

(1) The data and calculations used to estimate the absolute and relative errors associated with use of the mass-balance approach.

(2) The data and calculations used to estimate the mass of fluorine emitted from the process.

(3) The data and calculations used to determine the fractions of the mass emitted consisting of each reactant (FER_d), product (FEP), and by-product (FEB_k), including the preliminary calculations in § 98.123(b)(8)(i).

(d) *Emission factor and emission calculation factor method.* Retain the following records for each process for which the emission factor or emission calculation factor method was used to estimate emissions.

(1) Identify all continuous process vents with emissions of fluorinated GHGs that are less than 10,000 metric tons CO_2e per year and all continuous process vents with emissions of 10,000 metric tons CO_2e per year or more. Include the data and calculation used to develop the preliminary estimate of emissions for each process vent.

(2) Identify all batch process vents.

(3) For each vent, identify the method used to develop the factor (i.e., emission factor by emissions test or emission calculation factor).

(4) The emissions test data and reports (see § 98.124(c)(5)) and the calculations used to determine the process-vent-specific emission factor, including the actual process-vent-specific emission factor, the average hourly emission rate of each fluorinated GHG from the process vent during the test and the process feed rate, process production rate, or other process activity rate during the test.

(5) The process-vent-specific emission calculation factor and the calculations

used to determine the process-vent-specific emission calculation factor.

(6) The annual process production quantity or other process activity information in the appropriate units, along with the dates and time period during which the process was operating and dates and time periods the process vents are vented to the destruction device. As an alternative to date and time periods when process vents are vented to the destruction device, a facility may track dates and time periods that process vents by-pass the destruction device.

(7) Calculations used to determine annual emissions of each fluorinated GHG for each process and the total fluorinated GHG emissions for all processes, i.e., total for facility.

(e) *Destruction efficiency testing.* A fluorinated GHG production facility that destroys fluorinated GHGs and reflects this destruction in §98.123 must retain the emissions performance testing reports (including revised reports) for each destruction device. The emissions performance testing report must contain all information and data used to derive the destruction efficiency for each fluorinated GHG whose destruction the facility reflects in §98.123, as well as the key process and device conditions during the test. This information includes the following:

(1) Destruction efficiency (DE) determined for each fluorinated GHG whose destruction the facility reflects in §98.123, in accordance with §98.124(g)(1)(i) through (iv).

(2) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine destruction efficiency, including surrogates, and information on why the surrogate is sufficient to demonstrate destruction efficiency for each fluorinated GHG, consistent with requirements in §98.124(g)(1)(i) through (iv), vented to the destruction device.

(3) Mass flow rate of the stream containing the fluorinated GHG(s) or surrogate into the device during the test.

(4) Concentration (mass fraction) of each fluorinated GHG or surrogate in the stream flowing into the device during the test.

(5) Concentration (mass fraction) of each fluorinated GHG or surrogate at the outlet of the destruction device during the test.

(6) Mass flow rate at the outlet of the destruction device during the test.

(7) Test methods and analytical methods used to determine the mass flow rates and fluorinated GHG (or surrogate) concentrations of the streams flowing into and out of the destruction device during the test.

(8) Destruction device conditions that are normally monitored for device control, such as temperature, total mass flow rates into the device, and CO or O_2 levels.

(9) Name of all applicable Federal or State regulations that may apply to the destruction process.

(f) *Equipment leak records.* If you are subject to §98.123(d) of this subpart, you must maintain information on the number of each type of equipment; the service of each piece of equipment (gas, light liquid, heavy liquid); the concentration of each fluorinated GHG in the stream; each piece of equipment excluded from monitoring requirement; the time period each piece of equipment was in service, and the emission calculations for each fluorinated GHG for all processes. Depending on which equipment leak monitoring approach you follow, you must maintain information for equipment on the associated screening data concentrations for greater than or equal to 10,000 ppmv and associated screening data concentrations for less than 10,000 ppmv; associated actual screening data concentrations; and associated screening data and leak rate data (i.e., bagging) used to develop a unit-specific correlation. If you developed and follow a site-specific leak detection approach, provide the records for monitoring events and the emissions estimation calculations, as appropriate, consistent with the approach for equipment leak emission estimation in your GHG Monitoring Plan.

(g) *Container heel records.* If you vent residual fluorinated GHGs from containers, maintain the following records of the measurements and calculations used to estimate emissions of residual fluorinated GHGs from containers.

(i) If you measure the contents of each container, maintain records of these measurements and the calculations used to estimate emissions of each fluorinated GHG from each container size and type.

(ii) If you develop and apply container heel factors to estimate emissions, maintain records of the measurements and calculations used to develop the heel factor for each fluorinated GHG and each container size and type and of the number of containers of each fluorinated GHG and of each container size and type returned to your facility.

(h) *Missing data records.* Where missing data have been estimated pursuant to § 98.125, you must record the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data.

(i) *All facilities.* Dated records documenting the initial and periodic calibration of all analytical equipment used to determine the concentration of fluorinated GHGs, including but not limited to gas chromatographs, gas chromatography-mass spectrometry (GC/MS), gas chromatograph-electron capture detector (GC/ECD), fourier transform infrared (FTIR), and nuclear magnetic resonance (NMR) devices, and all mass measurement equipment such as weigh scales, flowmeters, and volumetric and density measures used to measure the quantities reported under this subpart, including the industry standards or manufacturer directions used for calibration pursuant to § 98.124(e), (f), (g), (m), and (n).

(j) GHG Monitoring Plans, as described in § 98.3(g)(5), must be completed by April 1, 2011.

(k) For fluorinated GHGs whose GWPs are not listed in Table A–1 to subpart A of this part, maintain records of the GWPs used to calculate facility-wide CO_2e emissions under § 98.127(j). Where you used your best estimate of the GWP, maintain records of the data and analysis used to develop that GWP, including the data elements at § 98.123(c)(1)(vi)(A)(*1*)through (*3*). If you have used QSARs to estimate the GWP, include information documenting the level of accuracy of the QSAR-derived GWP, including information on how the structure of the ‘‘target’’ fluorinated GHG is similar to the structures of the fluorinated GHGs used to model the radiative forcing and/or reaction rate of the ‘‘target’’ fluorinated GHG, the quality and quantity of the measurements of the radiative forcings and/or reaction rates of the fluorinated GHGs used to model these parameters for the ‘‘target’’ fluorinated GHG, any estimated uncertainties of the modeled forcings and/or reaction rates, and descriptions and results of any efforts to validate the QSAR model(s).

[75 FR 74831, Dec. 1, 2010, as amended at 77 FR 51490, Aug. 24, 2012]

§ 98.128 Definitions.

Except as provided in this section, all of the terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part. If a conflict exists between a definition provided in this subpart and a definition provided in subpart A, the definition in this subpart shall take precedence for the reporting requirements in this subpart.

Batch process or *batch operation* means a noncontinuous operation involving intermittent or discontinuous feed into equipment, and, in general, involves the emptying of the equipment after the batch operation ceases and prior to beginning a new operation. Addition of raw material and withdrawal of product do not occur simultaneously in a batch operation.

Batch emission episode means a discrete venting episode associated with a vessel in a process; a vessel may have more than one batch emission episode. For example, a displacement of vapor resulting from the charging of a vessel with a feed material will result in a discrete emission episode that will last through the duration of the charge and will have an average flow rate equal to the rate of the charge. If the vessel is then heated, there will also be another discrete emission episode resulting from the expulsion of expanded vapor. Other emission episodes also may occur from the same vessel and other vessels in the process, depending on process operations.

By-product means a chemical that is produced coincidentally during the production of another chemical.

Completely destroyed means destroyed with a destruction efficiency of 99.99 percent or greater.

Completely recaptured means 99.99 percent or greater of each fluorinated GHG is removed from a stream.

Continuous process or operation means a process where the inputs and outputs flow continuously throughout the duration of the process. Continuous processes are typically steady state.

Destruction device means any device used to destroy fluorinated GHG.

Destruction process means a process used to destroy fluorinated GHG in a destruction device such as a thermal incinerator or catalytic oxidizer.

Difficult-to-monitor means the equipment piece may not be monitored without elevating the monitoring personnel more than 2 meters (7 feet) above a support surface or it is not accessible in a safe manner when it is in fluorinated GHG service.

Dual mechanical seal pump and *dual mechanical seal agitator* means a pump or agitator equipped with a dual mechanical seal system that includes a barrier fluid system where the barrier fluid is not in light liquid service; each barrier fluid system is equipped with a sensor that will detect failure of the seal system, the barrier fluid system, or both; and meets the following requirements:

(1) Each dual mechanical seal system is operated with the barrier fluid at a pressure that is at all times (except periods of startup, shutdown, or malfunction) greater than the pump or agitator stuffing box pressure; or

(2) Equipped with a barrier fluid degassing reservoir that is routed to a process or fuel gas system or connected by a closed-vent system to a control device; or

(3) Equipped with a closed-loop system that purges the barrier fluid into a process stream.

Equipment (for the purposes of §98.123(d) and §98.124(f) only) means each pump, compressor, agitator, pressure relief device, sampling connection system, open-ended valve or line, valve, connector, and instrumentation system in fluorinated GHG service for a process subject to this subpart; and any destruction devices or closed-vent systems to which processes subject to this subpart are vented.

Fluorinated gas means any fluorinated GHG, CFC, or HCFC.

Fully fluorinated GHGs means fluorinated GHGs that contain only single bonds and in which all available valence locations are filled by fluorine atoms. This includes but is not limited to saturated perfluorocarbons, SF_6, NF_3, SF_5CF_3, fully fluorinated linear, branched and cyclic alkanes, fully fluorinated ethers, fully fluorinated tertiary amines, fully fluorinated aminoethers, and perfluoropolyethers.

In fluorinated GHG service means that a piece of equipment either contains or contacts a feedstock, by-product, or product that is a liquid or gas and contains at least 5 percent by weight fluorinated GHG.

In gas and vapor service means that a piece of equipment in regulated material service contains a gas or vapor at operating conditions.

In heavy liquid service means that a piece of equipment in regulated material service is not in gas and vapor service or in light liquid service.

In light liquid service means that a piece of equipment in regulated material service contains a liquid that meets the following conditions:

(1) The vapor pressure of one or more of the compounds is greater than 0.3 kilopascals at 20 °C.

(2) The total concentration of the pure compounds constituents having a vapor pressure greater than 0.3 kilopascals at 20 °C is equal to or greater than 20 percent by weight of the total process stream.

(3) The fluid is a liquid at operating conditions.

NOTE TO DEFINITION OF "IN LIGHT LIQUID SERVICE": Vapor pressures may be determined by standard reference texts or ASTM D–2879, (incorporated by reference, see §98.7).

In vacuum service means that equipment is operating at an internal pressure which is at least 5 kilopascals below ambient pressure.

Isolated intermediate means a product of a process that is stored before subsequent processing. An isolated intermediate is usually a product of chemical synthesis. Storage of an isolated intermediate marks the end of a process. Storage occurs at any time the intermediate is placed in equipment used solely for storage.

No external shaft pump and *No external shaft agitator* means any pump or agitator that is designed with no externally actuated shaft penetrating the pump or agitator housing.

Operating scenario means any specific operation of a process and includes the information specified in paragraphs (1) through (5) of this definition for each process. A change or series of changes to any of these elements, except for paragraph (4) of this definition, constitutes a different operating scenario.

(1) A description of the process, the specific process equipment used, and the range of operating conditions for the process.

(2) An identification of related process vents, their associated emissions episodes and durations, and calculations and engineering analyses to show the annual uncontrolled fluorinated GHG emissions from the process vent.

(3) The control or destruction devices used, as applicable, including a description of operating and/or testing conditions for any associated destruction device.

(4) The process vents (including those from other processes) that are simultaneously routed to the control or destruction device(s).

(5) The applicable monitoring requirements and any parametric level that assures destruction or removal for all emissions routed to the control or destruction device.

Process means all equipment that collectively functions to produce a fluorinated gas product, including an isolated intermediate (which is also a fluorinated gas product), or to transform a fluorinated gas product. A process may consist of one or more unit operations. For the purposes of this subpart, process includes any, all, or a combination of reaction, recovery, separation, purification, or other activity, operation, manufacture, or treatment which are used to produce a fluorinated gas product. For a continuous process, cleaning operations conducted may be considered part of the process, at the discretion of the facility. For a batch process, cleaning operations are part of the process. Ancillary activities are not considered a process or part of any process under this subpart. Ancillary activities include boilers and incinerators, chillers and refrigeration systems, and other equipment and activities that are not directly involved (i.e., they operate within a closed system and materials are not combined with process fluids) in the processing of raw materials or the manufacturing of a fluorinated gas product.

Process condenser means a condenser whose primary purpose is to recover material as an integral part of a process. All condensers recovering condensate from a process vent at or above the boiling point or all condensers in line prior to a vacuum source are considered process condensers. Typically, a primary condenser or condensers in series are considered to be integral to the process if they are capable of and normally used for the purpose of recovering chemicals for fuel value (i.e., net positive heating value), use, reuse or for sale for fuel value, use, or reuse.

Process vent (for the purposes of this subpart only) means a vent from a process vessel or vents from multiple process vessels within a process that are manifolded together into a common header, through which a fluorinated GHG-containing gas stream is, or has the potential to be, released to the atmosphere (or the point of entry into a control device, if any). Examples of process vents include, but are not limited to, vents on condensers used for product recovery, bottoms receivers, surge control vessels, reactors, filters, centrifuges, and process tanks. Process vents do not include vents on storage tanks, wastewater emission sources, or pieces of equipment.

Typical batch means a batch process operated within a range of operating conditions that are documented in an operating scenario. Emissions from a typical batch are based on the operating conditions that result in representative emissions. The typical batch defines the uncontrolled emissions for each emission episode defined under the operating scenario.

Uncontrolled fluorinated GHG emissions means a gas stream containing fluorinated GHG which has exited the process (or process condenser or control condenser, where applicable), but which has not yet been introduced into a destruction device to reduce the mass of fluorinated GHG in the stream. If the emissions from the process are not routed to a destruction device, uncontrolled emissions are those fluorinated GHG emissions released to the atmosphere.

Unsafe-to-monitor means that monitoring personnel would be exposed to an immediate danger as a consequence of monitoring the piece of equipment. Examples of unsafe-to-monitor equipment include, but are not limited to, equipment under extreme pressure or heat.

[75 FR 74831, Dec. 1, 2010, as amended at 77 FR 51490, Aug. 24, 2012]

Subpart M [Reserved]

Subpart N—Glass Production

§98.140 Definition of the source category.

(a) A glass manufacturing facility manufactures flat glass, container glass, pressed and blown glass, or wool fiberglass by melting a mixture of raw materials to produce molten glass and form the molten glass into sheets, containers, fibers, or other shapes. A glass manufacturing facility uses one or more continuous glass melting furnaces to produce glass.

(b) A glass melting furnace that is an experimental furnace or a research and development process unit is not subject to this subpart.

§98.141 Reporting threshold.

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

§98.142 GHGs to report.

You must report:

(a) CO_2 process emissions from each continuous glass melting furnace.

(b) CO_2 combustion emissions from each continuous glass melting furnace.

(c) CH_4 and N_2O combustion emissions from each continuous glass melting furnace. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit other than continuous glass melting furnaces. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.143 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each continuous glass melting furnace using the procedure in paragraphs (a) through (c) of this section.

(a) For each continuous glass melting furnace that meets the conditions specified in §98.33(b)(4)(ii) or (iii), you must calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to 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).

(b) For each continuous glass melting furnace that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO_2 emissions from the glass melting furnace by using either the procedure in paragraph (b)(1) of this section or the procedure in paragraph (b)(2) of this section, except as specified in paragraph (c) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to 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).

(2) Calculate and report the process and combustion CO_2 emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(vi) of this section.

(i) For each carbonate-based raw material charged to the furnace, obtain from the supplier of the raw material the carbonate-based mineral mass fraction.

(ii) Determine the quantity of each carbonate-based raw material charged to the furnace.

(iii) Apply the appropriate emission factor for each carbonate-based raw material charged to the furnace, as shown in Table N–1 to this subpart.

(iv) Use Equation N–1 of this section to calculate process mass emissions of CO_2 for each furnace:

$$E_{CO2} = \sum_{i=1}^{n} MF_i \cdot \left(M_i \cdot \frac{2000}{2205} \right) \cdot EF_i \cdot F_i \qquad \text{(Eq. N-1)}$$

Where:

E_{CO2} = Process emissions of CO_2 from the furnace (metric tons).

n = Number of carbonate-based raw materials charged to furnace.

MF_i = Annual average decimal mass fraction of carbonate-based mineral i in carbonate-based raw material i.

M_i = Annual amount of carbonate-based raw material i charged to furnace (tons).

2000/2205 = Conversion factor to convert tons to metric tons.

EF_i = Emission factor for carbonate-based raw material i (metric ton CO_2 per metric ton carbonate-based raw material as shown in Table N–1 to this subpart).

F_i = Decimal fraction of calcination achieved for carbonate-based raw material i, assumed to be equal to 1.0.

(v) You must calculate the total process CO_2 emissions from continuous glass melting furnaces at the facility using Equation N–2 of this section:

$$CO_2 = \sum_{i=1}^{k} E_{CO_2 i} \qquad \text{(Eq. N-2)}$$

Where:

CO_2 = Annual process CO_2 emissions from glass manufacturing facility (metric tons).

E_{CO2i} = Annual CO_2 emissions from glass melting furnace i (metric tons).

k = Number of continuous glass melting furnaces.

(vi) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions in the glass furnace according to the applicable requirements in subpart C.

(c) As an alternative to data provided by the raw material supplier, a value of 1.0 can be used for the mass fraction (MF_i) of carbonate-based mineral i in Equation N–1 of this section.

[75 FR 74831, Dec. 1, 2010, as amended at 78 FR 71954, Nov. 29, 2013]

§ 98.144 Monitoring and QA/QC requirements.

(a) You must measure annual amounts of carbonate-based raw materials charged to each continuous glass melting furnace from monthly measurements using plant instruments used for accounting purposes, such as calibrated scales or weigh hoppers. Total annual mass charged to glass melting furnaces at the facility shall be compared to records of raw material purchases for the year.

(b) You must measure carbonate-based mineral mass fractions at least annually to verify the mass fraction data provided by the supplier of the raw material; such measurements shall be based on sampling and chemical analysis using consensus standards that specify X-ray fluorescence. For measurements made in years prior to the emissions reporting year 2014, you may also use ASTM D3682–01 (Reapproved 2006) Standard Test Method for Major and Minor Elements in Combustion Residues from Coal Utilization Processes (incorporated by reference, *see* § 98.7) or ASTM D6349–09 Standard Test Method for Determination of Major and Minor Elements in Coal, Coke, and Solid Residues from Combustion of Coal and Coke by Inductively Coupled Plasma—Atomic Emission Spectrometry (incorporated by reference, *see* § 98.7).

(c) You must determine the annual average mass fraction for the carbonate-based mineral in each carbonate-based raw material by calculating an arithmetic average of the monthly data obtained from raw material suppliers or sampling and chemical analysis.

(d) You must determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using an industry consensus standard. This chemical analysis must be conducted using an x-ray fluorescence test or other enhanced testing method published by an industry consensus standards organization (e.g., ASTM, ASME, API, etc.).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66462, Oct. 28, 2010; 78 FR 71954, Nov. 29, 2013]

§98.145 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbonate raw materials consumed, etc.). If the monitoring and quality assurance procedures in §98.144 cannot be followed and data is missing, you must use the most appropriate of the missing data procedures in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For missing data on the monthly amounts of carbonate-based raw materials charged to any continuous glass melting furnace use the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes, such as purchase records.

(b) For missing data on the mass fractions of carbonate-based minerals in the carbonate-based raw materials assume that the mass fraction of each carbonate based mineral is 1.0.

§98.146 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) and (b) of this section, as applicable.

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required under §98.36 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) and (2) of this section:

(1) Annual quantity of each carbonate-based raw material charged to each continuous glass melting furnace and for all furnaces combined (tons).

(2) Annual quantity of glass produced by each glass melting furnace and by all furnaces combined (tons).

(b) If a CEMS is not used to determine CO_2 emissions from continuous glass melting furnaces, and process CO_2 emissions are calculated according to the procedures specified in §98.143(b), then you must report the following information as specified in paragraphs (b)(1) through (b)(9) of this section:

(1) Annual process emissions of CO_2 (metric tons) for each continuous glass melting furnace and for all furnaces combined.

(2) Annual quantity of each carbonate-based raw material charged (tons) to each continuous glass melting furnace and for all furnaces combined.

(3) Annual quantity of glass produced (tons) from each continuous glass melting furnace and from all furnaces combined.

(4) Carbonate-based mineral decimal mass fraction for each carbonate-based raw material charged to a continuous glass melting furnace.

(5) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous glass melting furnace, as specified in paragraphs (b)(5)(i) through (b)(5)(iii) of this section.

(i) Date of test.

(ii) Method(s) and any variations used in the analyses.

(iii) Mass fraction of each sample analyzed.

(6) The decimal fraction of calcination achieved for each carbonate-based raw material, if a value other than 1.0 is used to calculate process mass emissions of CO_2.

(7) Method used to determine decimal fraction of calcination.

(8) Total number of continuous glass melting furnaces.

(9) The number of times in the reporting year that missing data procedures were followed to measure monthly quantities of carbonate-based raw materials or mass fraction of the carbonate-based minerals for any continuous glass melting furnace (months).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66462, Oct. 28, 2010; 78 FR 71954, Nov. 29, 2013]

§ 98.147 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the records listed in paragraphs (a), (b), and (c) of this section.

(a) If a CEMS is used to measure emissions, then you must retain the records required under § 98.37 for the Tier 4 Calculation Methodology and the following information specified in paragraphs (a)(1) and (a)(2) of this section:

(1) Monthly glass production rate for each continuous glass melting furnace (tons).

(2) Monthly amount of each carbonate-based raw material charged to each continuous glass melting furnace (tons).

(b) If process CO_2 emissions are calculated according to the procedures specified in § 98.143(b), you must retain the records in paragraphs (b)(1) through (b)(5) of this section.

(1) Monthly glass production rate for each continuous glass melting furnace (metric tons).

(2) Monthly amount of each carbonate-based raw material charged to each continuous glass melting furnace (metric tons).

(3) Data on carbonate-based mineral mass fractions provided by the raw material supplier for all raw materials consumed annually and included in calculating process emissions in Equation N–1 of this subpart.

(4) Results of all tests used to verify the carbonate-based mineral mass fraction for each carbonate-based raw material charged to a continuous glass melting furnace, including the data specified in paragraphs (b)(4)(i) through (b)(4)(v) of this section.

(i) Date of test.

(ii) Method(s), and any variations of the methods, used in the analyses.

(iii) Mass fraction of each sample analyzed.

(iv) Relevant calibration data for the instrument(s) used in the analyses.

(v) Name and address of laboratory that conducted the tests.

(5) The decimal fraction of calcination achieved for each carbonate-based raw material, if a value other than 1.0 is used to calculate process mass emissions of CO_2.

(c) All other documentation used to support the reported GHG emissions.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71954, Nov. 29, 2013]

§ 98.148 Definitions.

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

TABLE N–1 TO SUBPART N OF PART 98—CO_2 EMISSION FACTORS FOR CARBONATE-BASED RAW MATERIALS

Carbonate-based raw material—mineral	CO_2 emission factor [a]
Limestone—$CaCO_3$	0.440
Dolomite—$CaMg(CO_3)_2$	0.477
Sodium carbonate/soda ash—Na_2CO_3	0.415
Barium carbonate—$BaCO_3$	0.223
Potassium carbonate—K_2CO_3	0.318
Lithium carbonate (Li_2CO_3)	0.596
Strontium carbonate ($SrCO_3$)	0.298

[a] Emission factors in units of metric tons of CO_2 emitted per metric ton of carbonate-based raw material charged to the furnace.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66462 , Oct. 28, 2010]

Subpart O—HCFC–22 Production and HFC–23 Destruction

§ 98.150 Definition of the source category.

The HCFC–22 production and HFC–23 destruction source category consists of HCFC–22 production processes and HFC–23 destruction processes.

(a) An HCFC–22 production process produces HCFC–22 (chlorodifluoromethane, or $CHClF_2$) from chloroform ($CHCl_3$) and hydrogen fluoride (HF).

(b) An HFC–23 destruction process is any process in which HFC–23 undergoes destruction. An HFC–23 destruction process may or may not be co-located with an HCFC–22 production process at the same facility.

§98.151 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an HCFC–22 production or HFC–23 destruction process and the facility meets the requirements of either §98.2(a)(1) or (a)(2).

§98.152 GHGs to report.

(a) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit following the requirements of subpart C.

(b) You must report HFC–23 emissions from HCFC–22 production processes and HFC–23 destruction processes.

§98.153 Calculating GHG emissions.

(a) The mass of HFC–23 generated from each HCFC–22 production process shall be estimated by using one of two methods, as applicable:

(1) Where the mass flow of the combined stream of HFC–23 and another reaction product (e.g., HCl) is measured, multiply the weekly (or more frequent) HFC–23 concentration measurement (which may be the average of more frequent concentration measurements) by the weekly (or more frequent) mass flow of the combined stream of HFC–23 and the other product. To estimate annual HFC–23 production, sum the weekly (or more frequent) estimates of the quantities of HFC–23 produced over the year. This calculation is summarized in Equation O–1 of this section:

$$G_{23} = \sum_{p=1}^{n} c_{23} * F_p * 10^{-3} \qquad \text{(Eq. O-1)}$$

Where:

G_{23} = Mass of HFC–23 generated annually (metric tons).

c_{23} = Fraction HFC–23 by weight in HFC–23/other product stream.

F_p = Mass flow of HFC–23/other product stream during the period p (kg).

p = Period over which mass flows and concentrations are measured.

n = Number of concentration and flow measurement periods for the year.

10^{-3} = Conversion factor from kilograms to metric tons.

(2) Where the mass of only a reaction product other than HFC–23 (either HCFC–22 or HCl) is measured, multiply the ratio of the weekly (or more frequent) measurement of the HFC–23 concentration and the weekly (or more frequent) measurement of the other product concentration by the weekly (or more frequent) mass produced of the other product. To estimate annual HFC–23 production, sum the weekly (or more frequent) estimates of the quantities of HFC–23 produced over the year. This calculation is summarized in Equation O–2 of this section, assuming that the other product is HCFC–22. If the other product is HCl, HCl may be substituted for HCFC–22 in Equations O–2 and O–3 of this section.

$$G_{23} = \sum_{p=1}^{n} \left(\frac{c_{23}}{c_{22}} \right) * P_{22} * 10^{-3} \qquad \text{(Eq. O-2)}$$

Where:

G_{23} = Mass of HFC–23 generated annually (metric tons).

c_{23} = Fraction HFC–23 by weight in HCFC–22/HFC–23 stream.

c_{22} = Fraction HCFC–22 by weight in HCFC–22/HFC–23 stream.

P_{22} = Mass of HCFC–22 produced over the period p (kg), calculated using Equation O–3 of this section.

p = Period over which masses and concentrations are measured.

n = Number of concentration and mass measurement periods for the year.

10^{-3} = Conversion factor from kilograms to metric tons.

(b) The mass of HCFC–22 produced over the period p shall be estimated by using Equation O–3 of this section:

$$P_{22} = LF * \left(O_{22} - U_{22} \right) \qquad \text{(Eq. O-3)}$$

Where:

P_{22} = Mass of HCFC–22 produced over the period p (kg).

O_{22} = mass of HCFC–22 that is measured coming out of the Production process over the period p (kg).

U_{22} = Mass of used HCFC–22 that is added to the production process upstream of the output measurement over the period p (kg).

LF = Factor to account for the loss of HCFC–22 upstream of the measurement. The value for LF shall be determined pursuant to §98.154(e).

(c) For HCFC–22 production facilities that do not use a destruction device or that have a destruction device that is not directly connected to the HCFC–22 production equipment, HFC–23 emissions shall be estimated using Equation O–4 of this section:

$$E_{23} = G_{23} - \left(S_{23} + OD_{23} + D_{23} + I_{23}\right) \qquad \text{(Eq. O-4)}$$

Where:

E_{23} = Mass of HFC–23 emitted annually (metric tons).

G_{23} = Mass of HFC–23 generated annually (metric tons).

S_{23} = Mass of HFC–23 sent off site for sale annually (metric tons).

OD_{23} = Mass of HFC–23 sent off site for destruction (metric tons).

D_{23} = Mass of HFC–23 destroyed on site (metric tons).

I_{23} = Increase in HFC–23 inventory = HFC–23 in storage at end of year—HFC–23 in storage at beginning of year (metric tons).

(d) For HCFC–22 production facilities that use a destruction device connected to the HCFC–22 production equipment, HFC–23 emissions shall be estimated using Equation O–5 of this section:

$$E_{23} = E_L + E_{PV} + E_D \qquad \text{(Eq. O-5)}$$

Where:

E_{23} = Mass of HFC–23 emitted annually (metric tons).

E_L = Mass of HFC–23 emitted annually from equipment leaks, calculated using Equation O–6 of this section (metric tons).

E_{PV} = Mass of HFC–23 emitted annually from process vents, calculated using Equation O–7 of this section (metric tons).

(1) The mass of HFC–23 emitted annually from equipment leaks (for use in Equation O–5 of this section) shall be estimated by using Equation O–6 of this section:

$$E_L = \sum_{p=1}^{n} \sum_{t} c_{23} * \left(F_{Gt} * N_{Gt} + F_{Lt} * N_{Lt}\right) * 10^{-3} \qquad \text{(Eq. O-6)}$$

Where:

E_L = Mass of HFC–23 emitted annually from equipment leaks (metric tons).

c_{23} = Fraction HFC–23 by weight in the stream(s) in the equipment.

F_{Gt} = The applicable leak rate specified in Table O–1 of this subpart for each source of equipment type and service t with a screening value greater than or equal to 10,000 ppmv (kg/hr/source).

N_{Gt} = The number of sources of equipment type and service t with screening values greater than or equal to 10,000 ppmv as determined according to § 98.154(i).

F_{Lt} = The applicable leak rate specified in Table O–1 of this subpart for each source of equipment type and service t with a screening value of less than 10,000 ppmv (kg/hr/source).

N_{Lt} = The number of sources of equipment type and service t with screening values less than 10,000 ppmv as determined according to § 98.154(j).

p = One hour.

n = Number of hours during the year during which equipment contained HFC–23.

t = Equipment type and service as specified in Table O–1 of this subpart .

10^{-3} = Factor converting kg to metric tons.

(2) The mass of HFC–23 emitted annually from process vents (for use in Equation O–5 of this section) shall be estimated by using Equation O–7 of this section:

$$E_{PV} = \sum_{p=1}^{n} ER_T * \left(\frac{PR_p}{PR_T}\right) * l_p * 10^{-3} \qquad \text{(Eq. O-7)}$$

Where:

E_{PV} = Mass of HFC–23 emitted annually from process vents (metric tons).
ER_T = The HFC–23 emission rate from the process vents during the period of the most recent test (kg/hr).
PR_p = The HCFC–22 production rate during the period p (kg/hr).
PR_T = The HCFC–22 production rate during the most recent test period (kg/hr).
l_p = The length of the period p (hours).
10^{-3} = Factor converting kg to metric tons.
n = The number of periods in a year.

(3) The total mass of HFC–23 emitted from destruction devices shall be estimated by using Equation O–8 of this section:

$$E_D = F_D - D_{23} \qquad \text{(Eq. O-8)}$$

Where:

E_D = Mass of HFC–23 emitted annually from the destruction device (metric tons).
F_D = Mass of HFC–23 fed into the destruction device annually (metric tons).
D_{23} = Mass of HFC–23 destroyed annually (metric tons).

(4) For facilities that destroy HFC–23, the total mass of HFC–23 destroyed shall be estimated by using Equation O–9 of this section:

$$D_{23} = F_D * DE \qquad \text{(Eq. O-9)}$$

Where:

D_{23} = Mass of HFC–23 destroyed annually (metric tons).
F_D = Mass of HFC–23 fed into the destruction device annually (metric tons).
DE = Destruction Efficiency of the destruction device (fraction).

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71955, Nov. 29, 2013]

§98.154 Monitoring and QA/QC requirements.

These requirements apply to measurements that are reported under this subpart or that are used to estimate reported quantities pursuant to §98.153.

(a) The concentrations (fractions by weight) of HFC–23 and HCFC–22 in the product stream shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples.

(b) The mass flow of the product stream containing the HFC–23 shall be measured at least weekly using weigh scales, flowmeters, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(c) The mass of HCFC–22 or HCl coming out of the production process shall be measured at least weekly using weigh scales, flowmeters, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(d) The mass of any used HCFC–22 added back into the production process upstream of the output measurement in paragraph (c) of this section shall be measured (when being added) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the mass in paragraph (c) of this section is measured by weighing containers that include returned heels as well as newly produced fluorinated GHGs, the returned heels shall be considered used fluorinated HCFC–22 for purposes of this paragraph (d) of this section and §98.153(b).

(e) The loss factor LF in Equation O–3 of this subpart for the mass of HCFC–22 produced shall have the value 1.015 or another value that can be demonstrated, to the satisfaction of the Administrator, to account for losses of HCFC–22 between the reactor and the point of measurement at the facility where production is being estimated.

(f) The mass of HFC–23 sent off site for sale shall be measured at least weekly (when being packaged) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(g) The mass of HFC–23 sent off site for destruction shall be measured at least weekly (when being packaged) using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than HFC–23, the concentration of the fluorinated GHG shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC–23 sent to another facility for destruction.

(h) The masses of HFC–23 in storage at the beginning and end of the year shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better.

(i) The number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv shall be determined using EPA Method 21 at 40 CFR part 60, appendix A–7, and defining a leak as follows:

(1) A leak source that could emit HFC–23, and

(2) A leak source at whose surface a concentration of fluorocarbons equal to or greater than 10,000 ppm is measured.

(j) The number of sources of equipment type t with screening values less than 10,000 ppmv shall be the difference between the number of leak sources of equipment type t that could emit HFC–23 and the number of sources of equipment type t with screening values greater than or equal to 10,000 ppmv as determined under paragraph (i) of this section.

(k) The mass of HFC–23 emitted from process vents shall be estimated at least monthly by incorporating the results of the most recent emissions test into Equation O–7 of this subpart. HCFC–22 production facilities that use a destruction device connected to the HCFC–22 production equipment shall conduct emissions tests at process vents at least once every five years or after significant changes to the process. Emissions tests shall be conducted in accordance with EPA Method 18 at 40 CFR part 60, appendix A–6, under conditions that are typical for the production process at the facility. The sensitivity of the tests shall be sufficient to detect an emission rate that would result in annual emissions of 200 kg of HFC–23 if sustained over one year.

(l) For purposes of Equation O–9 of this subpart, the destruction efficiency must be equated to the destruction efficiency determined during a new or previous performance test of the destruction device. HFC–23 destruction facilities shall conduct annual measurements of HFC–23 concentrations at the outlet of the destruction device in accordance with EPA Method 18 at 40 CFR part 60, appendix A–6. Three samples shall be taken under conditions that are typical for the production process and destruction device at the facility, and the average concentration of HFC–23 shall be determined. The sensitivity of the concentration measurement shall be sufficient to detect an outlet concentration equal to or less than the outlet concentration determined in the destruction efficiency performance test. If the concentration measurement indicates that the HFC–23 concentration is less than or equal to that measured during the performance test that is the basis for the destruction efficiency, continue to use the previously determined destruction efficiency. If the concentration measurement indicates that the HFC–23 concentration is greater than that measured during the performance test that is the basis for the destruction efficiency, facilities shall either:

(1) Substitute the higher HFC–23 concentration for that measured during the destruction efficiency performance test and calculate a new destruction efficiency, or

(2) Estimate the mass emissions of HFC–23 from the destruction device based on the measured HFC–23 concentration and volumetric flow rate determined by measurement of volumetric flow rate using EPA Method 2, 2A, 2C,2D, or 2F at 40 CFR part 60, appendix A–1, or Method 26 at 40 CFR part 60, appendix A–2. Determine the mass rate of HFC–23 into the destruction device by measuring the HFC–23 concentration and volumetric flow rate at the inlet or by a metering device for HFC–23 sent to the device. Determine a new destruction efficiency based on the mass flow rate of HFC–23 into and out of the destruction device.

(m) HCFC–22 production facilities shall account for HFC–23 generation and emissions that occur as a result of startups, shutdowns, and malfunctions, either recording HFC–23 generation and emissions during these events, or documenting that these events do not result in significant HFC–23 generation and/or emissions.

(n) The mass of HFC–23 fed into the destruction device shall be measured at least weekly using flow meters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of 1.0 percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than HFC–23, the concentrations of the HFC–23 shall be measured at least weekly using equipment and methods (e.g., gas chromatography) with an accuracy and precision of 5 percent or better at the concentrations of the process samples. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the HFC–23 destroyed.

(o) In their estimates of the mass of HFC–23 destroyed, HFC–23 destruction facilities shall account for any temporary reductions in the destruction efficiency that result from any startups, shutdowns, or malfunctions of the destruction device, including departures from the operating conditions defined in State or local permitting requirements and/or destruction device manufacturer specifications.

(p) Calibrate all flow meters, weigh scales, and combinations of volumetric and density measures using NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ISO, or others). Recalibrate all flow meters, weigh scales, and combinations of volumetric and density measures at the minimum frequency specified by the manufacturer.

(q) All gas chromatographs used to determine the concentration of HFC–23 in process streams shall be calibrated at least monthly through analysis of certified standards (or of calibration gases prepared from a high-concentration certified standard using a gas dilution system that meets the requirements specified in Method 205 at 40 CFR part 51, appendix M) with known HFC–23 concentrations that are in the same range (fractions by mass) as the process samples.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66462, Oct. 28, 2010; 78 FR 71955, Nov. 29, 2013]

§ 98.155 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required process sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the following requirements:

(1) For each missing value of the HFC–23 or HCFC–22 concentration, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. 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.

(2) For each missing value of the product stream mass flow or product mass, the substitute value of that parameter shall be a secondary product measurement where such a measurement is available. If that measurement is taken significantly downstream of the usual mass flow or mass measurement (e.g., at the shipping dock rather than near the reactor), the measurement shall be multiplied by 1.015 to compensate for losses. Where a secondary mass measurement is not available, the substitute value of the parameter shall be an estimate based on a related parameter. For example, if a flowmeter measuring the mass fed into a destruction device is rendered inoperable, then the mass fed into the destruction device may be estimated using the production rate and the previously observed relationship between the production rate and the mass flow rate into the destruction device.

§ 98.156 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), the HCFC–22 production facility shall report the following information at the facility level:

(1) Annual mass of HCFC–22 produced in metric tons.

(2) Loss Factor used to account for the loss of HCFC– 22 upstream of the measurement.

(3) Annual mass of reactants fed into the process in metric tons of reactant.

(4) The mass (in metric tons) of materials other than HCFC–22 and HFC–23 (i.e., unreacted reactants, HCl and other by-products) that occur in more than trace concentrations and that are permanently removed from the process.

(5) The method for tracking startups, shutdowns, and malfunctions and HFC–23 generation/emissions during these events.

(6) The names and addresses of facilities to which any HFC–23 was sent for destruction, and the quantities of HFC–23 (metric tons) sent to each.

(7) Annual mass of the HFC–23 generated in metric tons.

(8) Annual mass of any HFC–23 sent off site for sale in metric tons.

(9) Annual mass of any HFC–23 sent off site for destruction in metric tons.

(10) Mass of HFC–23 in storage at the beginning and end of the year, in metric tons.

(11) Annual mass of HFC–23 emitted in metric tons.

(12) Annual mass of HFC–23 emitted from equipment leaks in metric tons.

(13) Annual mass of HFC–23 emitted from process vents in metric tons.

(b) In addition to the information required by § 98.3(c), facilities that destroy HFC–23 shall report the following for each HFC–23 destruction process:

(1) Annual mass of HFC–23 fed into the destruction device.

(2) Annual mass of HFC–23 destroyed.

(3) Annual mass of HFC–23 emitted from the destruction device.

(c) Each HFC–23 destruction facility shall report the concentration (mass fraction) of HFC–23 measured at the outlet of the destruction device during the facility's annual HFC–23 concentration measurements at the outlet of the device. If the concentration of HFC–23 is below the detection limit of the measuring device, report the detection limit and that the concentration is below the detection limit.

(d) If the HFC–23 concentration measured pursuant to § 98.154(l) is greater than that measured during the performance test that is the basis for the destruction efficiency (DE), the facility shall report the revised destruction efficiency calculated under § 98.154(l) and the values used to calculate it, specifying whether § 98.154(l)(1) or § 98.154(l)(2) has been used for the calculation. Specifically, the facility shall report the following:

(1) Flow rate of HFC–23 being fed into the destruction device in kg/hr.

(2) Concentration (mass fraction) of HFC–23 at the outlet of the destruction device.

(3) Flow rate at the outlet of the destruction device in kg/hr.

(4) Emission rate (in kg/hr) calculated from paragraphs (d)(2) and (d)(3) of this section.

(5) Destruction efficiency (DE) calculated from paragraphs (d)(1) and (d)(4) of this section.

(e) By March 31, 2011 or within 60 days of commencing HFC–23 destruction, HFC–23 destruction facilities shall submit a one-time report including the following information for each destruction process:

(1) Destruction efficiency (DE).

(2) The methods used to determine destruction efficiency.

(3) The methods used to record the mass of HFC–23 destroyed.

(4) The name of other relevant federal or state regulations that may apply to the destruction process.

(5) If any changes are made that affect HFC–23 destruction efficiency or the methods used to record volume destroyed, then these changes must be reflected in a revision to this report. The revised report must be submitted to EPA within 60 days of the change.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66463, Oct. 28, 2010; 78 FR 71955, Nov. 29, 2013]

§ 98.157 Records that must be retained.

(a) In addition to the data required by § 98.3(g), HCFC–22 production facilities shall retain the following records:

(1) The data used to estimate HFC–23 emissions.

(2) Records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, volumetric and density measurements, and flowmeters used to measure the quantities reported under this rule, including the industry standards or manufacturer directions used for calibration pursuant to § 98.154(p) and (q).

(b) In addition to the data required by § 98.3(g), the HFC–23 destruction facilities shall retain the following records:

(1) Records documenting their one-time and annual reports in § 98.156(b) through (e).

(2) Records documenting the initial and periodic calibration of the gas chromatographs, weigh scales, volumetric and density measurements, and flowmeters used to measure the quantities reported under this subpart, including the industry standard practice or manufacturer directions used for calibration pursuant to § 98.154(p) and (q).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66463, Oct. 28, 2010]

§ 98.158 Definitions.

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

TABLE O–1 TO SUBPART O OF PART 98—EMISSION FACTORS FOR EQUIPMENT LEAKS

Equipment type	Service	Emission factor (kg/hr/source)	
		≥10,000 ppmv	<10,000 ppmv
Valves	Gas	0.0782	0.000131
Valves	Light liquid	0.0892	0.000165
Pump seals	Light liquid	0.243	0.00187
Compressor seals	Gas	1.608	0.0894
Pressure relief valves	Gas	1.691	0.0447
Connectors	All	0.113	0.0000810
Open-ended lines	All	0.01195	0.00150

Subpart P—Hydrogen Production

§ 98.160 Definition of the source category.

(a) A hydrogen production source category consists of facilities that produce hydrogen gas sold as a product to other entities.

(b) This source category comprises process units that produce hydrogen by reforming, gasification, oxidation, reaction, or other transformations of feedstocks.

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

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66463, Oct. 28, 2010]

§ 98.161 Reporting threshold.

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

§ 98.162 GHGs to report.

You must report:

(a) CO_2 emissions from each hydrogen production process unit.

(b) [Reserved]

(c) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than hydrogen production process units. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) For CO_2 collected and transferred off site, you must follow the requirements of subpart PP of this part.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66463, Oct. 28, 2010]

§ 98.163 Calculating GHG emissions.

You must calculate and report the annual CO_2 emissions from each hydrogen production process unit using the procedures specified in either paragraph (a) or (b) of this section.

(a) *Continuous Emissions Monitoring Systems (CEMS).* Calculate and report under this subpart the CO_2 emissions by operating and maintaining CEMS according to 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).

(b) *Fuel and feedstock material balance approach.* Calculate and report CO_2 emissions as the sum of the annual emissions associated with each fuel and feedstock used for hydrogen production by following paragraphs (b)(1) through (3) of this section. The carbon content and molecular weight shall be obtained from the analyses conducted in accordance with § 98.164(b)(2), (b)(3), or (b)(4), as applicable, or from the missing data procedures in § 98.165. If the analyses are performed annually, then the annual value shall be used as the monthly average. If the analyses are performed more frequently than monthly, use the arithmetic average of values obtained during the month as the monthly average.

(1) *Gaseous fuel and feedstock.* You must calculate the annual CO_2 emissions from each gaseous fuel and feedstock according to Equation P–1 of this section:

$$CO_2 = \left(\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n * \frac{MW}{MVC} \right) * 0.001 \qquad \text{(Eq. P-1)}$$

Where:

CO_2 = Annual CO_2 process emissions arising from fuel and feedstock consumption (metric tons/yr).

$Fdstk_n$ = Volume or mass of the gaseous fuel or feedstock used in month n (scf (at standard conditions of 68 °F and atmospheric pressure) or kg of fuel or feedstock).

CC_n = Average carbon content of the gaseous fuel or feedstock for month n (kg carbon per kg of fuel or feedstock).

MW_n = Average molecular weight of the gaseous fuel or feedstock for month n (kg/kg-mole). If you measure mass, the term "MW_n/MVC" is replaced with "1".

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

k = Months in the year.

44/12 = Ratio of molecular weights, CO_2 to carbon. 0.001 = Conversion factor from kg to metric tons.

(2) *Liquid fuel and feedstock.* You must calculate the annual CO_2 emissions from each liquid fuel and feedstock according to Equation P–2 of this section:

$$CO_2 = \left(\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n \right) * 0.001 \qquad \text{(Eq. P-2)}$$

Where:

CO_2 = Annual CO_2 emissions arising from fuel and feedstock consumption (metric tons/yr).

$Fdstk_n$ = Volume or mass of the liquid fuel or feedstock used in month n (gallons or kg of fuel or feedstock).

CC_n = Average carbon content of the liquid fuel or feedstock, for month n (kg carbon per gallon or kg of fuel or feedstock).

k = Months in the year.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(3) *Solid fuel and feedstock.* You must calculate the annual CO_2 emissions

from each solid fuel and feedstock according to Equation P–3 of this section:

$$CO_2 = \left(\sum_{n=1}^{k} \frac{44}{12} * Fdstk_n * CC_n \right) * 0.001 \qquad \text{(Eq. P-3)}$$

Where:

CO_2 = Annual CO_2 emissions from fuel and feedstock consumption in metric tons per month (metric tons/yr).

$Fdstk_n$ = Mass of solid fuel or feedstock used in month n (kg of fuel or feedstock).

CC_n = Average carbon content of the solid fuel or feedstock, for month n (kg carbon per kg of fuel or feedstock).

k = Months in the year.

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.001 = Conversion factor from kg to metric tons.

(c) If GHG emissions from a hydrogen production process unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66463, Oct. 28, 2010; 75 FR 79157, Dec. 17, 2010; 78 FR 71955, Nov. 29, 2013]

§ 98.164 Monitoring and QA/QC requirements.

The GHG emissions data for hydrogen production process units must be quality-assured as specified in paragraphs (a) or (b) of this section, as appropriate for each process unit:

(a) If a CEMS is used to measure GHG emissions, then the facility must comply with the monitoring and QA/QC procedures specified in § 98.34(c).

(b) If a CEMS is not used to measure GHG emissions, then you must:

(1) Calibrate all oil and gas flow meters that are used to measure liquid and gaseous feedstock volumes (except for gas billing meters) according to the monitoring and QA/QC requirements for the Tier 3 methodology in § 98.34(b)(1). Perform oil tank drop measurements (if used to quantify liquid fuel or feedstock consumption) according to § 98.34(b)(2). Calibrate all solids weighing equipment according to the procedures in § 98.3(i).

(2) Determine the carbon content and the molecular weight annually of standard gaseous hydrocarbon fuels and feedstocks having consistent composition (*e.g.*, natural gas). For other gaseous fuels and feedstocks (*e.g.*, biogas, refinery gas, or process gas), sample and analyze no less frequently than weekly to determine the carbon content and molecular weight of the fuel and feedstock.

(3) Determine the carbon content of fuel oil, naphtha, and other liquid fuels and feedstocks at least monthly, except annually for standard liquid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for liquid fuels and feedstocks delivered by bulk transport (*e.g.*, by truck or rail).

(4) Determine the carbon content of coal, coke, and other solid fuels and feedstocks at least monthly, except annually for standard solid hydrocarbon fuels and feedstocks having consistent composition, or upon delivery for solid fuels and feedstocks delivered by bulk transport (*e.g.*, by truck or rail).

(5) You must use the following applicable methods to determine the carbon content for all fuels and feedstocks, and molecular weight of gaseous fuels and feedstocks. Alternatively, you may use the results of chromatographic

analysis of the fuel and feedstock, provided that the chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions; and the methods used for operation, maintenance, and calibration of the chromatograph are documented in the written monitoring plan for the unit under § 98.3(g)(5).

(i) ASTM D1945–03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(ii) ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(iii) ASTM D2013–07 Standard Practice of Preparing Coal Samples for Analysis (incorporated by reference, *see* § 98.7).

(iv) ASTM D2234/D2234M–07 Standard Practice for Collection of a Gross Sample of Coal (incorporated by reference, *see* § 98.7).

(v) ASTM D2597–94 (Reapproved 2004) Standard Test Method for Analysis of Demethanized Hydrocarbon Liquid Mixtures Containing Nitrogen and Carbon Dioxide by Gas Chromatography (incorporated by reference, *see* § 98.7).

(vi) ASTM D3176–89 (Reapproved 2002), Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, *see* § 98.7).

(vii) ASTM D3238–95 (Reapproved 2005), Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method (incorporated by reference, *see* § 98.7).

(viii) ASTM D4057–06 Standard Practice for Manual Sampling of Petroleum and Petroleum Products (incorporated by reference, *see* § 98.7).

(ix) ASTM D4177–95 (Reapproved 2005) Standard Practice for Automatic Sampling of Petroleum and Petroleum Products (incorporated by reference, *see* § 98.7).

(x) 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).

(xi) 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).

(xii) ASTM D6609–08 Standard Guide for Part-Stream Sampling of Coal (incorporated by reference, see § 98.7).

(xiii) ASTM D6883–04 Standard Practice for Manual Sampling of Stationary Coal from Railroad Cars, Barges, Trucks, or Stockpiles (incorporated by reference, *see* § 98.7).

(xiv) ASTM D7430–08ae1 Standard Practice for Mechanical Sampling of Coal (incorporated by reference, *see* § 98.7).

(xv) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, *see* § 98.7).

(xvi) GPA 2261–00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, *see* § 98.7).

(xvii) ISO 3170: Petroleum Liquids—Manual sampling—Third Edition (incorporated by reference, *see* § 98.7).

(xviii) ISO 3171: Petroleum Liquids—Automatic pipeline sampling—Second Edition (incorporated by reference, *see* § 98.7).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79157, Dec. 17, 2010; 78 FR 71955, Nov. 29, 2013]

§ 98.165 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation), a substitute data value for the missing parameter must be used in the calculations as specified in paragraphs (a), (b), and (c) of this section:

(a) For each missing value of the monthly fuel and feedstock consumption, the substitute data value must be the best available estimate of the fuel and feedstock consumption, based on all available process data (e.g., hydrogen production, electrical load, and operating hours). You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of the carbon content or molecular weight of the fuel and feedstock, the substitute data value must be the arithmetic average of the quality-assured values of carbon contents or molecular weight of the fuel and feedstock immediately preceding and immediately following the missing data incident. If no quality-assured data on carbon contents or molecular weight of the fuel and feedstock are available prior to the missing data incident, the substitute data value must be the first quality-assured value for carbon contents or molecular weight of the fuel and feedstock obtained after the missing data period. You must document and keep records of the procedures used for all such estimates.

(c) For missing CEMS data, you must use the missing data procedures in §98.35.

§98.166 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate, and paragraphs (c) and (d) of this section:

(a) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under §98.36 for the Tier 4 Calculation Methodology and the following information in this paragraph (a):

(1) Unit identification number and annual CO_2 emissions.

(2) Annual quantity of hydrogen produced (metric tons) for each process unit.

(3) Annual quantity of ammonia produced (metric tons), if applicable, for each process unit.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the following information for each hydrogen production process unit:

(1) Unit identification number and annual CO_2 emissions.

(2) Monthly consumption of each fuel and feedstock used for hydrogen production and its type (scf or kg of gaseous fuels and feedstocks, gallons or kg of liquid fuels and feedstocks, kg of solid fuels and feedstocks).

(3) Annual quantity of hydrogen produced (metric tons).

(4) Annual quantity of ammonia produced, if applicable (metric tons).

(5) Monthly analyses of carbon content for each fuel and feedstock used in hydrogen production (kg carbon/kg of gaseous and solid fuels and feedstocks, kg carbon per gallon or kg of liquid fuels and feedstocks).

(6) Monthly analyses of the molecular weight of gaseous fuels and feedstocks (kg/kg-mole) used, if any.

(c) Quantity of CO_2 collected and transferred off site in either gas, liquid, or solid forms, following the requirements of subpart PP of this part.

(d) Annual quantity of carbon other than CO_2 collected and transferred off site in either gas, liquid, or solid forms (kg carbon).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66463, Oct. 28, 2010; 78 FR 71955, Nov. 29, 2013]

§98.167 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records specified in paragraphs (a) through (b) of this section for each hydrogen production facility.

(a) If a CEMS is used to measure CO_2 emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in §98.37.

(b) If a CEMS is not used to measure CO_2 emissions, then you must retain records of all analyses and calculations conducted as listed in §§98.166(b), (c), and (d).

(c) For units using the calculation methodologies described in §98.163(b), the records required under §98.3(g) must include both the company records and a detailed explanation of how company records are used to estimate the following:

(1) Fuel and feedstock consumption, when solid fuel and feedstock is combusted and a CEMS is not used to measure GHG emissions.

(2) Fossil fuel consumption, when, pursuant to §98.33(e), the owner or operator of a unit that uses CEMS to quantify CO_2 emissions and that combusts both fossil and biogenic fuels separately reports the biogenic portion of the total annual CO_2 emissions.

(3) Sorbent usage, if the methodology in §98.33(d) is used to calculate CO_2 emissions from sorbent.

(d) The owner or operator must document the procedures used to ensure the accuracy of the estimates of fuel and feedstock usage and sorbent usage (as applicable) in § 98.163(b), including, but not limited to, calibration of weighing equipment, fuel and feedstock flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71956, Nov. 29, 2013]

§ 98.168 Definitions.

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

Subpart Q—Iron and Steel Production

§ 98.170 Definition of the source category.

The iron and steel production source category includes facilities with any of the following processes: taconite iron ore processing, integrated iron and steel manufacturing, cokemaking not collocated with an integrated iron and steel manufacturing process, direct reduction furnaces not collocated with an integrated iron and steel manufacturing process, and electric arc furnace (EAF) steelmaking not collocated with an integrated iron and steel manufacturing process. Integrated iron and steel manufacturing means the production of steel from iron ore or iron ore pellets. At a minimum, an integrated iron and steel manufacturing process has a basic oxygen furnace for refining molten iron into steel. Each cokemaking process and EAF process located at a facility with an integrated iron and steel manufacturing process is part of the integrated iron and steel manufacturing facility.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71955, Nov. 29, 2013]

§ 98.171 Reporting threshold.

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

§ 98.172 GHGs to report.

(a) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit following the requirements of subpart C except for flares. Stationary combustion units include, but are not limited to, by-product recovery coke oven battery combustion stacks, blast furnace stoves, boilers, process heaters, reheat furnaces, annealing furnaces, flame suppression, ladle reheaters, and other miscellaneous combustion sources.

(b) You must report CO_2 emissions from flares that burn blast furnace gas or coke oven gas according to the procedures in § 98.253(b)(1) of subpart Y (Petroleum Refineries) of this part. When using the alternatives set forth in § 98.253(b)(1)(ii)(B) and § 98.253(b)(1)(iii)(C), you must use the default CO_2 emission factors for coke oven gas and blast furnace gas from Table C–1 to subpart C in Equations Y–2 and Y–3 of subpart Y. You must report CH_4 and N_2O emissions from flares according to the requirements in § 98.33(c)(2) using the emission factors for coke oven gas and blast furnace gas in Table C–2 to subpart C of this part.

(c) You must report process CO_2 emissions from each taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery combustion stack; coke pushing process; sinter process; EAF; decarburization vessel; and direct reduction furnace by following the procedures in this subpart.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66463, Oct. 28, 2010]

§ 98.173 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, decarburization vessel, and direct reduction furnace using the procedures in either paragraph (a) or (b) of this section. Calculate and report the annual process CO_2 emissions from the coke pushing process according to paragraph (c) of this section.

(a) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining CEMS according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO_2 emissions using the procedure in paragraph (b)(1) or (b)(2) of this section.

(1) *Carbon mass balance method.* Calculate the annual mass emissions of CO_2 for the process as specified in paragraphs (b)(1)(i) through (b)(1)(vii) of this section. The calculations are based on the annual mass of inputs and outputs to the process and an annual analysis of the respective weight fraction of carbon as determined according to the procedures in § 98.174(b). If you have a process input or output other than CO_2 in the exhaust gas that contains carbon that is not included in Equations Q–1 through Q–7 of this section, you must account for the carbon and mass rate of that process input or output in your calculations according to the procedures in § 98.174(b)(5).

(i) For taconite indurating furnaces, estimate CO_2 emissions using Equation Q–1 of this section.

$$CO_2 = \frac{44}{12} * \left[(F_s) * (C_{sf}) + (F_g) * (C_{gf}) * \frac{MW}{MVC} * 0.001 + (F_l) * (C_{lf}) * 0.001 + (O) * (C_o) - (P) * (C_p) - (R) * (C_R) \right] \qquad \text{(Eq. Q-1)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the taconite indurating furnace (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(F_s) = Annual mass of the solid fuel used (metric tons).

(C_{sf}) = Carbon content of the solid fuel, from the fuel analysis (expressed as a decimal fraction).

(F_g) = Annual volume of the gaseous fuel used (scf).

(C_{gf}) = Average carbon content of the gaseous fuel, from the fuel analysis results (kg C per kg of fuel).

MW = Molecular weight of the gaseous fuel (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

0.001 = Conversion factor from kg to metric tons.

(F_l) = Annual volume of the liquid fuel used (gallons).

(C_{lf}) = Carbon content of the liquid fuel, from the fuel analysis results (kg C per gallon of fuel).

(O) = Annual mass of greenball (taconite) pellets fed to the furnace (metric tons).

(C_O) = Carbon content of the greenball (taconite) pellets, from the carbon analysis results (expressed as a decimal fraction).

(P) = Annual mass of fired pellets produced by the furnace (metric tons).

(C_p) = Carbon content of the fired pellets, from the carbon analysis results (expressed as a decimal fraction).

(R) = Annual mass of air pollution control residue collected (metric tons).

(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (expressed as a decimal fraction).

(ii) For basic oxygen process furnaces, estimate CO_2 emissions using Equation Q–2 of this section.

$$\begin{aligned} CO_2 = \frac{44}{12} * \Big[&(Iron) * (C_{Iron}) + (Scrap) * (C_{Scrap}) + (Flux) * (C_{Flux}) \\ &+ (Carbon) * (C_{Carbon}) - (Steel) * (C_{Steel}) - (Slag) * (C_{Slag}) - (R) * (C_R) \Big] \end{aligned} \qquad \text{(Eq. Q-2)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the basic oxygen furnace (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(Iron) = Annual mass of molten iron charged to the furnace (metric tons).

(C_{Iron}) = Carbon content of the molten iron, from the carbon analysis results (expressed as a decimal fraction).

(Scrap) = Annual mass of ferrous scrap charged to the furnace (metric tons).
(C_{Scrap}) = Carbon content of the ferrous scrap, from the carbon analysis results (expressed as a decimal fraction).
(Flux) = Annual mass of flux materials (e.g., limestone, dolomite) charged to the furnace (metric tons).
(C_{Flux}) = Carbon content of the flux materials, from the carbon analysis results (expressed as a decimal fraction).
(Carbon) = Annual mass of carbonaceous materials (e.g., coal, coke) charged to the furnace (metric tons).
(C_{Carbon}) = Carbon content of the carbonaceous materials, from the carbon analysis results (expressed as a decimal fraction).
(Steel) = Annual mass of molten raw steel produced by the furnace (metric tons).
(C_{Steel}) = Carbon content of the steel, from the carbon analysis results (expressed as a decimal fraction).
(Slag) = Annual mass of slag produced by the furnace (metric tons).
(C_{Slag}) = Carbon content of the slag, from the carbon analysis (expressed as a decimal fraction).
(R) = Annual mass of air pollution control residue collected (metric tons).
(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (expressed as a decimal fraction)

(iii) For non-recovery coke oven batteries, estimate CO_2 emissions using Equation Q–3 of this section.

$$CO_2 = \frac{44}{12} * \left[(Coal) * (C_{Coal}) - (Coke) * (C_{Coke}) - (R) * (C_R) \right] \qquad \text{(Eq. Q-3)}$$

Where:
CO_2 = Annual CO_2 mass emissions from the non-recovery coke oven battery (metric tons).
44/12 = Ratio of molecular weights, CO_2 to carbon.
(Coal) = Annual mass of coal charged to the battery (metric tons).
(C_{Coal}) = Carbon content of the coal, from the carbon analysis results (expressed as a decimal fraction).
(Coke) = Annual mass of coke produced by the battery (metric tons).
(C_{Coke}) = Carbon content of the coke, from the carbon analysis results (expressed as a decimal fraction).
(R) = Annual mass of air pollution control residue collected (metric tons).
(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (expressed as a decimal fraction)

(iv) For sinter processes, estimate CO_2 emissions using Equation Q–4 of this section.

$$CO_2 = \frac{44}{12} * \left[(F_g) * (C_{gf}) * \frac{MW}{MVC} * 0.001 + (Feed) * (C_{Feed}) - (\text{Sinter}) * (C_{Sinter}) - (R) * (C_R) \right] \qquad \text{(Eq. Q-4)}$$

Where:
CO_2 = Annual CO_2 mass emissions from the sinter process (metric tons).
44/12 = Ratio of molecular weights, CO_2 to carbon.
(F_g) = Annual volume of the gaseous fuel used (scf).
(C_{gf}) = Carbon content of the gaseous fuel, from the fuel analysis results (kg C per kg of fuel).
MW = Molecular weight of the gaseous fuel (kg/kg-mole).
MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).
0.001 = Conversion factor from kg to metric tons.
(Feed) = Annual mass of sinter feed material (metric tons).
(C_{Feed}) = Carbon content of the mixed sinter feed materials that form the bed entering the sintering machine, from the carbon analysis results (expressed as a decimal fraction).
(Sinter) = Annual mass of sinter produced (metric tons).
(C_{Sinter}) = Carbon content of the sinter pellets, from the carbon analysis results (expressed as a decimal fraction).
(R) = Annual mass of air pollution control residue collected (metric tons).
(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (expressed as a decimal fraction).

(v) For EAFs, estimate CO_2 emissions using Equation Q–5 of this section.

$$CO_2 = \frac{44}{12} * \left[\begin{array}{l} (Iron) * (C_{Iron}) + (Scrap) * (C_{Scrap}) + (Flux) * (C_{Flux}) + (Electrode) * (C_{Electrode}) + (Carbon) \\ * (C_{Carbon}) - (Steel) * (C_{Steel}) + (F_g) * (C_{gf}) * \frac{MW}{MVC} * 0.001 - (Slag) * (C_{Slag}) - (R) * (CR) \end{array} \right] \quad \text{(Eq. Q-5)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the EAF (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(Iron) = Annual mass of direct reduced iron (if any) charged to the furnace (metric tons).

(C_{Iron}) = Carbon content of the direct reduced iron, from the carbon analysis results (expressed as a decimal fraction).

(Scrap) = Annual mass of ferrous scrap charged to the furnace (metric tons).

(C_{Scrap}) = Carbon content of the ferrous scrap, from the carbon analysis results (expressed as a decimal fraction).

(Flux) = Annual mass of flux materials (*e.g.*, limestone, dolomite) charged to the furnace (metric tons).

(C_{Flux}) = Carbon content of the flux materials, from the carbon analysis results (expressed as a decimal fraction).

(Electrode) = Annual mass of carbon electrode consumed (metric tons).

($C_{Electrode}$) = Carbon content of the carbon electrode, from the carbon analysis results (expressed as a decimal fraction).

(Carbon) = Annual mass of carbonaceous materials (*e.g.*, coal, coke) charged to the furnace (metric tons).

(C_{Carbon}) = Carbon content of the carbonaceous materials, from the carbon analysis results (expressed as a decimal fraction).

(Steel) = Annual mass of molten raw steel produced by the furnace (metric tons).

(C_{Steel}) = Carbon content of the steel, from the carbon analysis results (expressed as a decimal fraction).

(F_g) = Annual volume of the gaseous fuel used (scf at 60 degrees F and one atmosphere).

(C_{gf}) = Average carbon content of the gaseous fuel, from the fuel analysis results (kg C per kg of fuel).

(MW) = Molecular weight of the gaseous fuel (kg/kg-mole).

(MVC) = Molar volume conversion factor (836.6 scf per kg-mole at standard conditions of 60 degrees F and one atmosphere).

(0.001) = Conversion factor from kg to metric tons.

(Slag) = Annual mass of slag produced by the furnace (metric tons).

(C_{Slag}) = Carbon content of the slag, from the carbon analysis results (expressed as a decimal fraction).

(R) = Annual mass of air pollution control residue collected (metric tons).

(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (expressed as a decimal fraction).

(vi) For decarburization vessels, estimate CO_2 emissions using Equation Q–6 of this section.

$$CO_2 = \frac{44}{12} * \left\{ (Steel) * \left[(C_{Steelin}) - (C_{Steelout}) \right] - (R) * (C_R) \right\} \quad \text{(Eq. Q-6)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the decarburization vessel (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(Steel) = Annual mass of molten steel charged to the vessel (metric tons).

($C_{Steelin}$) = Carbon content of the molten steel before decarburization, from the carbon analysis results (expressed as a decimal fraction).

($C_{Steelout}$) = Carbon content of the molten steel after decarburization, from the carbon analysis results (expressed as a decimal fraction).

(R) = Annual mass of air pollution control residue collected (metric tons).

(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (expressed as a decimal fraction).

(vii) For direct reduction furnaces, estimate CO_2 emissions using Equation Q–7 of this section.

$$CO_2 = \frac{44}{12} * \Big[\left(F_g\right) * \left(C_{gf}\right) * \frac{MW}{MVC} * 0.001 + \left(Ore\right) * \left(C_{Ore}\right) + (Carbon) * \left(C_{Carbon}\right) + (Other) * \left(C_{Other}\right) - (Iron)\ \left(C_{Iron}\right) - (NM) * \left(C_{NM}\right) - (R) * \left(C_R\right) \Big] \qquad \text{(Eq. Q-7)}$$

Where:

CO_2 = Annual CO_2 mass emissions from the direct reduction furnace (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(F_g) = Annual volume of the gaseous fuel used (scf).

(C_{gf}) = Carbon content of the gaseous fuel, from the fuel analysis results (kg C per kg of fuel).

MW = Molecular weight of the gaseous fuel (kg/kg-mole).

MVC = Molar volume conversion factor (849.5 scf per kg-mole at standard conditions).

0.001 = Conversion factor from kg to metric tons.

(Ore) = Annual mass of iron ore or iron ore pellets fed to the furnace (metric tons).

(C_{Ore}) = Carbon content of the iron ore or iron ore pellets, from the carbon analysis results (expressed as a decimal fraction).

(Carbon) = Annual mass of carbonaceous materials (e.g., coal, coke) charged to the furnace (metric tons).

(C_{Carbon}) = Carbon content of the carbonaceous materials, from the carbon analysis results (expressed as a decimal fraction).

(Other) = Annual mass of other materials charged to the furnace (metric tons).

(C_{Other}) = Average carbon content of the other materials charged to the furnace, from the carbon analysis results (expressed as a decimal fraction).

(Iron) = Annual mass of iron produced (metric tons).

(C_{Iron}) = Carbon content of the iron, from the carbon analysis results (expressed as a decimal fraction).

(NM) = Annual mass of non-metallic materials produced by the furnace (metric tons).

(C_{NM}) = Carbon content of the non-metallic materials, from the carbon analysis results (expressed as a decimal fraction).

(R) = Annual mass of air pollution control residue collected (metric tons).

(C_R) = Carbon content of the air pollution control residue, from the carbon analysis results (expressed as a decimal fraction).

(2) *Site-specific emission factor method.* Conduct a performance test and measure CO_2 emissions from all exhaust stacks for the process and measure either the feed rate of materials into the process or the production rate during the test as described in paragraphs (b)(2)(i) through (b)(2)(iv) of this section.

(i) You must measure the process production rate or process feed rate, as applicable, during the performance test according to the procedures in § 98.174(c)(5) and calculate the average rate for the test period in metric tons per hour.

(ii) You must calculate the hourly CO_2 emission rate using Equation Q–8 of this section and determine the average hourly CO_2 emission rate for the test.

$$CO_2 = 5.18 \text{ x } 10^{-7} \star C_{CO2} \star \text{Q} \star \left(\frac{100 - \%H_2O}{100} \right) \qquad \text{(Eq. Q-8)}$$

Where:

CO_2 = CO_2 mass emission rate, corrected for moisture (metric tons/hr).

5.18×10^{-7} = Conversion factor (metric tons/scf − % CO_2).

C_{CO2} = Hourly CO_2 concentration, dry basis (% CO_2).

Q = Hourly stack gas volumetric flow rate (scfh).

%H_2O = Hourly moisture percentage in the stack gas.

(iii) You must calculate a site-specific emission factor for the process in metric tons of CO_2 per metric ton of feed or production, as applicable, by dividing the average hourly CO_2 emission rate during the test by the average hourly feed or production rate during the test.

(iv) You must calculate CO_2 emissions for the process by multiplying the emission factor by the total amount of feed or production, as applicable, for the reporting period.

(c) You must determine emissions of CO_2 from the coke pushing process in $mtCO_2e$ by multiplying the metric tons of coal charged to the by-product recovery and non-recovery coke ovens during the reporting period by 0.008.

(d) If GHG emissions from a taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, EAF, decarburization vessel, or direct reduction furnace are vented through a stack equipped with a CEMS that complies with the Tier 4 methodology in subpart C of this part, or through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in §98.33(a)(4) and comply with all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66464, Oct. 28, 2010; 78 FR 71956, Nov. 29, 2013]

§ 98.174 Monitoring and QA/QC requirements.

(a) If you operate and maintain a CEMS that measures CO_2 emissions consistent with subpart C of this part, you must meet the monitoring and QA/QC requirements of §98.34(c).

(b) If you determine CO_2 emissions using the carbon mass balance procedure in §98.173(b)(1), you must:

(1) Except as provided in paragraph (b)(4) of this section, determine the mass of each process input and output other than fuels using the same plant instruments or procedures that are used for accounting purposes (such as weigh hoppers, belt weigh feeders, weighed purchased quantities in shipments or containers, combination of bulk density and volume measurements, etc.), record the totals for each process input and output for each calendar month, and sum the monthly mass to determine the annual mass for each process input and output. Determine the mass rate of fuels using the procedures for combustion units in §98.34. No determination of the mass of steel output from decarburization vessels is required.

(2) Except as provided in paragraph (b)(4) of this section, determine the carbon content of each process input and output annually for use in the applicable equations in §98.173(b)(1) based on analyses provided by the supplier or by the average carbon content determined by collecting and analyzing at least three samples each year using the standard methods specified in paragraphs (b)(2)(i) through (b)(2)(vi) of this section as applicable.

(i) ASTM C25–06, Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference, *see* §98.7) for limestone, dolomite, and slag.

(ii) 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) for coal, coke, and other carbonaceous materials.

(iii) ASTM E1915–07a, Standard Test Methods for Analysis of Metal Bearing Ores and Related Materials by Combustion Infrared-Absorption Spectrometry (incorporated by reference, *see* §98.7) for iron ore, taconite pellets, and other iron-bearing materials.

(iv) ASTM E1019–08, Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques (incorporated by reference, *see* §98.7) for iron and ferrous scrap.

(v) ASM CS–104 UNS No. G10460—Alloy Digest April 1985 (Carbon Steel of Medium Carbon Content) (incorporated by reference, *see* §98.7); ISO/TR 15349–1:1998, Unalloyed steel—Determination of low carbon content, Part 1: Infrared absorption method after combustion in an electric resistance furnace (by peak separation) (1998–10–15) First Edition (incorporated by reference, *see* § 98.7); or ISO/TR 15349–3:1998, Unalloyed steel-Determination of low carbon content Part 3: Infrared absorption method after combustion in an electric resistance furnace (with preheating) (1998–10–15) First Edition (incorporated by reference, *see* § 98.7) as applicable for steel.

(vi) For each process input that is a fuel, determine the carbon content and molecular weight (if applicable) using the applicable methods listed in § 98.34.

(3) For solid ferrous materials charged to basic oxygen process furnaces or EAFs that differ in carbon content, you may determine a weighted average carbon content based on the carbon content of each type of ferrous material and the average weight percent of each type that is used. Examples of these different ferrous materials include carbon steel, low carbon steel, stainless steel, high alloy steel, pig iron, iron scrap, and direct reduced iron.

(4) If you document that a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(5) Except as provided in paragraph (b)(4) of this section, you must determine the annual carbon content and monthly mass rate of any input or output that contains carbon that is not listed in the equations in § 98.173(b)(1) using the procedures in paragraphs (b)(1) and (b)(2) of this section.

(c) If you determine CO_2 emissions using the site-specific emission factor procedure in § 98.173(b)(2), you must:

(1) Conduct an annual performance test that is based on representative performance (i.e., performance based on normal operating conditions) of the affected process.

(2)(i) For the exhaust from basic oxygen furnaces, EAFs, decarburization vessels, and direct reduction furnaces, sample the furnace exhaust for at least three complete production cycles that start when the furnace is being charged and end after steel or iron and slag have been tapped. For EAFs that produce both carbon steel and stainless or specialty (low carbon) steel, develop an emission factor for the production of both types of steel.

(ii) For the exhaust from continuously charged EAFs, sample the exhaust for a period spanning at least three hours. For EAFs that produce both carbon steel and stainless or specialty (low carbon) steel, develop an emission factor for the production of both types of steel.

(3) For taconite indurating furnaces, non-recovery coke batteries, and sinter processes, sample for at least 3 hours.

(4) Conduct the stack test using EPA Method 3A at 40 CFR part 60, appendix A–2 to measure the CO_2 concentration, Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A–1 or Method 26 at 40 CFR part 60, appendix A–2 to determine the stack gas volumetric flow rate, and Method 4 at 40 CFR part 60, at appendix A–3 to determine the moisture content of the stack gas.

(5) Determine the mass rate of process feed or process production (as applicable) during the test using the same plant instruments or procedures that are used for accounting purposes (such as weigh hoppers, belt weigh feeders, combination of bulk density and volume measurements, etc.)

(6) If your process operates under different conditions as part of normal operations in such a manner that CO_2 emissions change by more than 20 percent (e.g., routine changes in the carbon content of the sinter feed or change in grade of product), you must perform emission testing and develop separate emission factors for these different operating conditions and determine emissions based on the number of hours the process operates and the production or feed rate (as applicable) at each specific different condition.

(7) If your EAF and decarburization vessel exhaust to a common emission control device and stack, you must sample each process in the ducts before the emissions are combined, sample each process when only one process is operating, or sample the combined emissions when both processes are operating and base the site-specific emission factor on the steel production rate of the EAF.

(8) The results of a performance test must include the analysis of samples, determination of emissions, and raw data. The performance test report must contain all information and data used to derive the emission factor.

(d) For a coke pushing process, determine the metric tons of coal charged to the coke ovens and record the totals for each pushing process for each calendar month. Coal charged to coke ovens can be measured using weigh belts or a combination of measuring volume and bulk density.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66464, Oct. 28, 2010; 78 FR 71957, Nov. 29, 2013]

§98.175 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in §98.173 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must follow the missing data procedures in §98.255(b) of subpart Y (Petroleum Refineries) of this part for flares burning coke oven gas or blast furnace gas. You must document and keep records of the procedures used for all such estimates.

(a) Except as provided in §98.174(b)(4), 100 percent data availability is required for the carbon content of inputs and outputs for facilities that estimate emissions using the carbon mass balance procedure in §98.173(b)(1) or facilities that estimate emissions using the site-specific emission factor procedure in §98.173(b)(2).

(b) For missing records of the monthly mass or volume of carbon-containing inputs and outputs using the carbon mass balance procedure in §98.173(b)(1), the substitute data value must be based on the best available estimate of the mass of the input or output material from all available process data or data used for accounting purposes.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66464, Oct. 28, 2010; 78 FR 71958, Nov. 29, 2013]

§98.176 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information required in paragraphs (a) through (h) of this section for each coke pushing operation; taconite indurating furnace; basic oxygen furnace; non-recovery coke oven battery; sinter process; EAF; decarburization vessel; direct reduction furnace; and flare burning coke oven gas or blast furnace gas. For reporting year 2010, the information required in paragraphs (a) through (h) of this section is not required for decarburization vessels that are not argon-oxygen decarburization vessels. For reporting year 2011 and each subsequent reporting year, the information in paragraphs (a) through (h) of this section must be reported for all decarburization vessels.

(a) Unit identification number and annual CO_2 emissions (in metric tons).

(b) Annual production quantity (in metric tons) for taconite pellets, coke, sinter, iron, and raw steel.

(c) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under §98.36 for the Tier 4 Calculation Methodology.

(d) If a CEMS is not used to measure CO_2 emissions, then you must report for each process whether the emissions were determined using the carbon mass balance method in §98.173(b)(1) or the site-specific emission factor method in §98.173(b)(2).

(e) If you use the carbon mass balance method in §98.173(b)(1) to determine CO_2 emissions, you must, except as provided in §98.174(b)(4), report the following information for each process:

(1) The carbon content of each process input and output used to determine CO_2 emissions.

(2) Whether the carbon content was determined from information from the supplier or by laboratory analysis, and if by laboratory analysis, the method used.

(3) The annual volume of each type of gaseous fuel (reported separately for each type in standard cubic feet), the annual volume of each type of liquid fuel (reported separately for each type in gallons), and the annual mass (in

metric tons) of each other process inputs and outputs used to determine CO_2 emissions.

(4) The molecular weight of gaseous fuels.

(5) If you used the missing data procedures in § 98.175(b), you must report how the monthly mass for each process input or output with missing data was determined and the number of months the missing data procedures were used.

(f) If you used the site-specific emission factor method in § 98.173(b)(2) to determine CO_2 emissions, you must report the following information for each process:

(1) The measured average hourly CO_2 emission rate during the test (in metric tons per hour).

(2) The average hourly feed or production rate (as applicable) during the test (in metric tons per hour).

(3) The site-specific emission factor (in metric tons of CO_2 per metric ton of feed or production, as applicable).

(4) The annual feed or production rate (as applicable) used to estimate annual CO_2 emissions (in metric tons).

(g) The annual amount of coal charged to the coke ovens (in metric tons).

(h) For flares burning coke oven gas or blast furnace gas, the information specified in § 98.256(e) of subpart Y (Petroleum Refineries) of this part.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66464, Oct. 28, 2010; 78 FR 71958, Nov. 29, 2013]

§ 98.177 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (e) of this section, as applicable. Facilities that use CEMS to measure emissions must also retain records of the verification data required for the Tier 4 Calculating Methodology in § 98.36(e).

(a) Records of all analyses and calculations conducted, including all information reported as required under § 98.176.

(b) When the carbon mass balance method is used to estimate emissions for a process, the monthly mass of each process input and output that are used to determine the annual mass, except that no determination of the mass of steel output from decarburization vessels is required.

(c) Production capacity (in metric tons per year) for the production of taconite pellets, coke, sinter, iron, and raw steel.

(d) Annual operating hours for each taconite indurating furnace, basic oxygen furnace, non-recovery coke oven battery, sinter process, electric arc furnace, decarburization vessel, and direct reduction furnace.

(e) Facilities must keep records that include a detailed explanation of how company records or measurements are used to determine all sources of carbon input and output and the metric tons of coal charged to the coke ovens (e.g., weigh belts, a combination of measuring volume and bulk density). You also must document the procedures used to ensure the accuracy of the measurements of fuel usage including, but not limited to, calibration of weighing equipment, fuel flow meters, coal usage including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66464, Oct. 28, 2010; 78 FR 71958, Nov. 29, 2013]

§ 98.178 Definitions.

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

Subpart R—Lead Production

§ 98.180 Definition of the source category.

The lead production source category consists of primary lead smelters and secondary lead smelters. A primary lead smelter is a facility engaged in the production of lead metal from lead sulfide ore concentrates through the use of pyrometallurgical techniques. A secondary lead smelter is a facility at which lead-bearing scrap materials (including but not limited to, lead-acid batteries) are recycled by smelting into elemental lead or lead alloys.

§ 98.181 Reporting threshold.

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

§ 98.182 GHGs to report.

You must report:

(a) Process CO_2 emissions from each smelting furnace used for lead production.

(b) CO_2 combustion emissions from each smelting furnace used for lead production.

(c) CH_4 and N_2O combustion emissions from each smelting furnace used for lead production. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than smelting furnaces used for lead production. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.183 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each smelting furnace using the procedure in paragraphs (a) and (b) of this section.

(a) For each smelting furnace that meets the conditions specified in § 98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to 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).

(b) For each smelting furnace that is not subject to the requirements in paragraph (a) of this section, calculate and report the process and combustion CO_2 emissions from the smelting furnace by using the procedure in either paragraph (b)(1) or (b)(2) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to 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).

(2) Calculate and report process and combustion CO_2 emissions separately using the procedures specified in paragraphs (b)(2)(i) through (b)(2)(iii) of this section.

(i) For each smelting furnace, determine the annual mass of carbon in each carbon-containing material, other than fuel, that is fed, charged, or otherwise introduced into the smelting furnace and estimate annual process CO_2 emissions using Equation R–1 of this section. Carbon-containing materials include carbonaceous reducing agents. If you document that a specific material contributes less than 1 percent of the total carbon into the process, you do not have to include the material in your calculation using Equation R–1 of this section.

$$E_{CO2} = \frac{44}{12} \times \frac{2000}{2205} \times \left[(Ore \times C_{Ore}) + (Scrap \times C_{Scrap}) + (Flux \times C_{Flux}) + (Carbon \times C_{Carbon}) + (Other \times C_{Other}) \right] \qquad \text{(Eq. R-1)}$$

Where:

E_{CO2} = Annual process CO_2 emissions from an individual smelting furnace (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

2000/2205 = Conversion factor to convert tons to metric tons.

Ore = Annual mass of lead ore charged to the smelting furnace (tons).

C_{Ore} = Carbon content of the lead ore, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

Scrap = Annual mass of lead scrap charged to the smelting furnace (tons).

C_{Scrap} = Carbon content of the lead scrap, from the carbon analysis (percent by weight, expressed as a decimal fraction).

Flux = Annual mass of flux materials (e.g., limestone, dolomite) charged to the smelting furnace (tons).

C_{Flux} = Carbon content of the flux materials, from the carbon analysis (percent by weight, expressed as a decimal fraction).

Carbon = Annual mass of carbonaceous materials (e.g., coal, coke) charged to the smelting furnace (tons).

C_{Carbon} = Carbon content of the carbonaceous materials, from the carbon analysis (percent by weight, expressed as a decimal fraction).

Other = Annual mass of any other material containing carbon, other than fuel, fed, charged, or otherwise introduced into the smelting furnace (tons).

C_{Other} = Carbon content of the other material from the carbon analysis results (percent by weight, expressed as a decimal fraction).

(ii) Determine the combined annual process CO_2 emissions from the smelting furnaces at your facility using Equation R–2 of this section.

$$CO_2 = \sum_{1}^{k} E_{CO2_k} \qquad \text{(Eq. R-2)}$$

Where:

CO_2 = Annual process CO_2 emissions from smelting furnaces at facility used for lead production (metric tons).

E_{CO2_k} = Annual process CO_2 emissions from smelting furnace k calculated using Equation R–1 of this section (metric tons/year).

k = Total number of smelting furnaces at facility used for lead production.

(iii) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions from the smelting furnaces according to the applicable requirements in subpart C.

§ 98.184 Monitoring and QA/QC requirements.

If you determine process CO_2 emissions using the carbon mass balance procedure in § 98.183(b)(2)(i) and (b)(2)(ii), you must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) Determine the annual mass for each material used for the calculations of annual process CO_2 emissions using Equation R–1 of this subpart by summing the monthly mass for the material determined for each month of the calendar year. The monthly mass may be determined using plant instruments used for accounting purposes, including either direct measurement of the quantity of the material placed in the unit or by calculations using process operating information.

(b) For each material identified in paragraph (a) of this section, you must determine the average carbon content of the material consumed or used in the calendar year using the methods specified in either paragraph (b)(1) or (b)(2) of this section. If you document that a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(1) Information provided by your material supplier.

(2) Collecting and analyzing at least three representative samples of the material each year. The carbon content of the material must be analyzed at least annually using the methods (and their QA/QC procedures) specified in paragraphs (b)(2)(i) through (b)(2)(iii) of this section, as applicable.

(i) ASTM E1941–04, Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys (incorporated by reference, see § 98.7) for analysis of metal ore and alloy product.

(ii) 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), for analysis of carbonaceous reducing agents and carbon electrodes.

(iii) ASTM C25–06, Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference, see § 98.7) for analysis of flux materials such as limestone or dolomite.

§ 98.185 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations in § 98.183 is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing data for the carbon content for the smelting furnaces at your facility that estimate annual process CO_2 emissions using the carbon mass balance procedure in §98.183(b)(2)(i) and (ii), 100 percent data availability is required. You must repeat the test for average carbon contents of inputs according to the procedures in §98.184(b) if data are missing.

(b) For missing records of the monthly mass of carbon-containing materials, the substitute data value must be based the best available estimate of the mass of the material from all available process data or data used for accounting purposes (such as purchase records).

§98.186 Data reporting procedures.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable.

(a) If a CEMS is used to measure CO_2 emissions according to the requirements in §98.183(a) or (b)(1), then you must report under this subpart the relevant information required by §98.36 and the information specified in paragraphs (a)(1) through (a)(4) of this section.

(1) Identification number of each smelting furnace.

(2) Annual lead product production capacity (tons).

(3) Annual production for each lead product (tons).

(4) Total number of smelting furnaces at facility used for lead production.

(b) If a CEMS is not used to measure CO_2 emissions, and you measure CO_2 emissions according to the requirements in §98.183(b)(2)(i) and (b)(2)(ii), then you must report the information specified in paragraphs (b)(1) through (b)(9) of this section.

(1) Identification number of each smelting furnace. (2) Annual process CO_2 emissions (in metric tons) from each smelting furnace as determined by Equation R–1 of this subpart.

(3) Annual lead product production capacity for the facility and each smelting furnace(tons).

(4) Annual production for each lead product (tons).

(5) Total number of smelting furnaces at facility used for production of lead products reported in paragraph (b)(4) of this section.

(6) Annual material quantity for each material used for the calculation of annual process CO_2 emissions using Equation R–1 of this subpart for each smelting furnace (tons).

(7) Annual average of the carbon content determinations for each material used for the calculation of annual process CO_2 emissions using Equation R–1 of this subpart for each smelting furnace.

(8) List the method used for the determination of carbon content for each material reported in paragraph (b)(7) of this section (e.g., supplier provided information, analyses of representative samples you collected).

(9) If you use the missing data procedures in §98.185(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

§98.187 Records that must be retained.

In addition to the records required by §98.3(g), each annual report must contain the information specified in paragraphs (a) through (c) of this section, as applicable to the smelting furnaces at your facility.

(a) If a CEMS is used to measure combined process and combustion CO_2 emissions according to the requirements in §98.183(a) or (b)(1), then you must retain the records required for the Tier 4 Calculation Methodology in §98.37 and the information specified in paragraphs (a)(1) through (a)(3) of this section.

(1) Monthly smelting furnace production quantity for each lead product (tons).

(2) Number of smelting furnace operating hours each month.

(3) Number of smelting furnace operating hours in calendar year.

(b) If the carbon mass balance procedure is used to determine process CO_2 emissions according to the requirements in § 98.183(b)(2)(i) and (b)(2)(ii), then you must retain under this subpart the records specified in paragraphs (b)(1) through (b)(5) of this section.

(1) Monthly smelting furnace production quantity for each lead product (tons).

(2) Number of smelting furnace operating hours each month.

(3) Number of smelting furnace operating hours in calendar year.

(4) Monthly material quantity consumed, used, or produced for each material included for the calculations of annual process CO_2 emissions using Equation R–1 of this subpart (tons).

(5) Average carbon content determined and records of the supplier provided information or analyses used for the determination for each material included for the calculations of annual process CO_2 emissions using Equation R–1 of this subpart.

(c) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input to each smelting furnace, including documentation of any materials excluded from Equation R–1 of this subpart that contribute less than 1 percent of the total carbon into or out of the process. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in an smelting furnace including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.188 Definitions.

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

Subpart S—Lime Manufacturing

§ 98.190 Definition of the source category.

(a) Lime manufacturing plants (LMPs) engage in the manufacture of a lime product by calcination of limestone, dolomite, shells or other calcareous substances as defined in 40 CFR 63.7081(a)(1).

(b) This source category includes all LMPs unless the LMP is located at a kraft pulp mill, soda pulp mill, sulfite pulp mill, or only processes sludge containing calcium carbonate from water softening processes. The lime manufacturing source category consists of marketed and non-marketed lime manufacturing facilities.

(c) Lime kilns at pulp and paper manufacturing facilities must report emissions under subpart AA of this part (Pulp and Paper Manufacturing).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66464, Oct. 28, 2010; 78 FR 71958, Nov. 29, 2013]

§ 98.191 Reporting threshold.

You must report GHG emissions under this subpart if your facility is a lime manufacturing plant as defined in § 98.190 and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.192 GHGs to report.

You must report:

(a) CO_2 process emissions from lime kilns.

(b) CO_2 emissions from fuel combustion at lime kilns.

(c) N_2O and CH_4 emissions from fuel combustion at each lime kiln. You must report these emissions under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

(d) CO_2, N_2O, and CH_4 emissions from each stationary fuel combustion unit other than lime kilns. You must report these emissions under 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

(e) CO_2 collected and transferred off site under 40 CFR part 98, following the requirements of subpart PP of this part (Suppliers of Carbon Dioxide (CO_2)).

§ 98.193 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from all lime kilns combined using the procedure in paragraphs (a) and (b) of this section.

(a) If all lime kilns meet the conditions specified in § 98.33(b)(4)(ii) or (iii), you must calculate and report under this subpart the combined process and combustion CO_2 emissions from all lime kilns by operating and maintaining a CEMS to measure CO_2 emissions according to 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).

(b) If CEMS are not required to be used to determine CO_2 emissions from all lime kilns under paragraph (a) of this section, then you must calculate and report the process and combustion CO_2 emissions from the lime kilns by using the procedures in either paragraph (b)(1) or (b)(2) of this section.

(b) * * *

(1) Calculate and report under this subpart the combined process and combustion CO_2 emissions from all lime kilns by operating and maintaining a CEMS to measure CO_2 emissions from all lime kilns according to 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).

(2) Calculate and report process and combustion CO_2 emissions from all lime kilns separately using the procedures specified in paragraphs (b)(2)(i) through (v) of this section.

(i) You must calculate a monthly emission factor for each type of lime produced using Equation S–1 of this section. Calcium oxide and magnesium oxide content must be analyzed monthly for each lime product type that is produced:

$$EF_{LIME,i,n} = \left[\left(SR_{CaO} * CaO_{i,n}\right) + \left(SR_{MgO} * MgO_{i,n}\right)\right] * \frac{2000}{2205} \qquad \text{(Eq. S-1)}$$

Where:

$EF_{LIME,i,n}$ = Emission factor for lime type i, for month n (metric tons CO_2/ton lime).

SR_{CaO} = Stoichiometric ratio of CO_2 and CaO for calcium carbonate [see Table S–1 of this subpart] (metric tons CO_2/metric tons CaO).

SR_{MgO} = Stoichiometric ratio of CO_2 and MgO for magnesium carbonate (See Table S–1 of this subpart) (metric tons CO_2/metric tons MgO).

$CaO_{i,n}$ = Calcium oxide content for lime type i, for month n, determined according to § 98.194(c) (metric tons CaO/metric ton lime).

$MgO_{i,n}$ = Magnesium oxide content for lime type i, for month n, determined according to § 98.194(c) (metric tons MgO/metric ton lime).

2000/2205 = Conversion factor for tons to metric tons.

(ii) You must calculate a monthly emission factor for each type of calcined byproduct or waste sold (including lime kiln dust) using Equation S–2 of this section:

$$EF_{LKD,i,n} = \left[\left(SR_{CaO} * CaO_{LKD,i,n}\right) + \left(SR_{MgO} * MgO_{LKD,i,n}\right)\right] * \frac{2000}{2205} \qquad \text{(Eq. S-2)}$$

Where:

$EF_{LKD,i,n}$ = Emission factor for calcined lime byproduct/waste type i sold, for month n (metric tons CO_2/ton lime byproduct).

SR_{CaO} = Stoichiometric ratio of CO_2 and CaO for calcium carbonate (see Table S–1 of this subpart((metric tons CO_2/metric tons CaO).

SR_{MgO} = Stoichiometric ratio of CO_2 and MgO for magnesium carbonate (See Table S–1 of this subpart) (metric tons CO_2/metric tons MgO).

$CaO_{LKD,i,n}$ = Calcium oxide content for calcined lime byproduct/waste type i sold, for month n (metric tons CaO/metric ton lime).

$MgO_{LKD,i,n}$ = Magnesium oxide content for calcined lime byproduct/waste type i sold, for month n (metric tons MgO/metric ton lime).

2000/2205 = Conversion factor for tons to metric tons.

(iii) You must calculate the annual CO_2 emissions from each type of calcined byproduct or waste that is not sold (including lime kiln dust and scrubber sludge) using Equation S–3 of this section:

$$E_{waste,i} = \left[\left(SR_{CaO} * CaO_{waste,i}\right) + \left(SR_{MgO} * MgO_{waste,i}\right)\right] * M_{waste,i} * \frac{2000}{2205} \qquad \text{(Eq. S-3)}$$

Where:

$E_{waste,i}$ = Annual CO_2 emissions for calcined lime byproduct or waste type i that is not sold (metric tons CO_2).

SR_{CaO} = Stoichiometric ratio of CO_2 and CaO for calcium carbonate (see Table S–1 of this subpart) (metric tons CO_2/metric tons CaO).

SR_{MgO} = Stoichiometric ratio of CO_2 and MgO for magnesium carbonate (See Table S–1 of this subpart) (metric tons CO_2/metric tons MgO).

$CaO_{waste,i}$ = Calcium oxide content for calcined lime byproduct or waste type i that is not sold (metric tons CaO/metric ton lime).

$MgO_{waste,i}$ = Magnesium oxide content for calcined lime byproduct or waste type i that is not sold (metric tons MgO/metric ton lime).

$M_{waste,i}$ = Annual weight or mass of calcined byproducts or wastes for lime type i that is not sold (tons).

2000/2205 = Conversion factor for tons to metric tons.

(iv) You must calculate annual CO_2 process emissions for all lime kilns using Equation S–4 of this section:

$$E_{CO_2} \sum_{i=1}^{t}\sum_{n=1}^{12}\left(EF_{LIME,i,n} * M_{LIME,i,n}\right) + \sum_{i=1}^{b}\sum_{n=1}^{12} EF_{LKD,i,n} * M_{LKD,i,n}\Big) + \sum_{i=1}^{z} E_{waste,i} \qquad \text{(Eq. S-4)}$$

Where:

E_{CO2} = Annual CO_2 process emissions from lime production from all lime kilns (metric tons/year).

$EF_{LIME,i,n}$ = Emission factor for lime type i produced, in calendar month n (metric tons CO_2/ton lime) from Equation S–1 of this section.

$M_{LIME,i,n}$ = Weight or mass of lime type i produced in calendar month n (tons).

$EF_{LKD,i,n}$ = Emission factor of calcined byproducts or wastes sold for lime type i in calendar month n, (metric tons CO_2/ton byproduct or waste) from Equation S–2 of this section.

$M_{LKD,i,n}$ = Monthly weight or mass of calcined byproducts or waste sold (such as lime kiln dust, LKD) for lime type i in calendar month n (tons).

$E_{waste,i}$ = Annual CO_2 emissions for calcined lime byproduct or waste type i that is not sold (metric tons CO_2) from Equation S–3 of this section.

t = Number of lime types produced

b = Number of calcined byproducts or wastes that are sold.

z = Number of calcined byproducts or wastes that are not sold.

(v) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2 emissions from each lime kiln according to the applicable requirements in subpart C.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66464, Oct. 28, 2010; 78 FR 71958, Nov. 29, 2013]

§ 98.194 Monitoring and QA/QC requirements.

(a) You must determine the total quantity of each type of lime product that is produced and each calcined byproduct or waste (such as lime kiln dust) that is sold. The quantities of each should be directly measured monthly with the same plant instruments used for accounting purposes, including but not limited to, calibrated weigh feeders, rail or truck scales, and barge measurements. The direct measurements of each lime product shall be reconciled annually with the difference in the beginning of and end of year inventories for these products, when measurements represent lime sold.

(b) You must determine the annual quantity of each calcined byproduct or waste generated that is not sold by either direct measurement using the same instruments identified in paragraph (a) of this section or by using a calcined byproduct or waste generation rate.

(c) You must determine the chemical composition (percent total CaO and percent total MgO) of each type of lime product that is produced and each type of calcined byproduct or waste sold according to paragraph (c)(1) or (2) of this section. You must determine the chemical composition of each type of lime product that is produced and each type of calcined byproduct or waste sold on a monthly basis. You must determine the chemical composition for each type of calcined byproduct or waste that is not sold on an annual basis.

(1) ASTM C25–06 Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference—*see* §98.7).

(2) The National Lime Association's CO_2 Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision-National Lime Association (incorporated by reference—see §98.7).

(d) You must use the analysis of calcium oxide and magnesium oxide content of each lime product that is produced and that is collected during the same month as the production data in monthly calculations.

(e) You must follow the quality assurance/quality control procedures (including documentation) in National Lime Association's CO_2 Emissions Calculation Protocol for the Lime Industry English Units Version, February 5, 2008 Revision—National Lime Association (incorporated by reference—*see* §98.7).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66465, Oct. 28, 2010; 78 FR 71958, Nov. 29, 2013]

§98.195 Procedures for estimating missing data.

For the procedure in §98.193(b)(1), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., oxide content, quantity of lime products, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) or (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the quantity of lime produced (by lime type), and quantity of calcined byproduct or waste produced and sold, the substitute data value shall be the best available estimate based on all available process data or data used for accounting purposes.

(b) For missing values related to the CaO and MgO content, you must conduct a new composition test according to the standard methods in §98.194 (c)(1) or (c)(2).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66465, Oct. 28, 2010; 78 FR 71959, Nov. 29, 2013]

§98.196 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable.

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required by §98.36 and the information listed in paragraphs (a)(1) through (8) of this section.

(1) Method used to determine the quantity of lime that is produced and quantity of lime that is sold.

(2) Method used to determine the quantity of calcined lime byproduct or waste sold.

(3) Beginning and end of year inventories for each lime product that is produced, by type.

(4) Beginning and end of year inventories for calcined lime byproducts or wastes sold, by type.

(5) Annual amount of calcined lime byproduct or waste sold, by type (tons).

(6) Annual amount of lime product sold, by type (tons).

(7) Annual amount of calcined lime byproduct or waste that is not sold, by type (tons).

(8) Annual amount of lime product not sold, by type (tons).

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in paragraphs (b)(1) through (17) of this section.

(1) Annual CO_2 process emissions from all lime kilns combined (metric tons).

(2) Monthly emission factors (metric ton CO_2/ton lime product) for each lime product type produced.

(3) Monthly emission factors for each calcined byproduct or waste by lime type that is sold.

(4) Standard method used (ASTM or NLA testing method) to determine chemical compositions of each lime type produced and each calcined lime byproduct or waste type.

(5) Monthly results of chemical composition analysis of each type of lime product produced and calcined byproduct or waste sold.

(6) Annual results of chemical composition analysis of each type of lime byproduct or waste that is not sold.

(7) Method used to determine the quantity of lime produced and/or lime sold.

(8) Monthly amount of lime product sold, by type (tons).

(9) Method used to determine the quantity of calcined lime byproduct or waste sold.

(10) Monthly amount of calcined lime byproduct or waste sold, by type (tons).

(11) Annual amount of calcined lime byproduct or waste that is not sold, by type (tons).

(12) Monthly weight or mass of each lime type produced (tons).

(13) Beginning and end of year inventories for each lime product that is produced.

(14) Beginning and end of year inventories for calcined lime byproducts or wastes sold.

(15) Annual lime production capacity (tons) per facility.

(16) Number of times in the reporting year that missing data procedures were followed to measure lime production (months) or the chemical composition of lime products sold (months).

(17) Indicate whether CO_2 was used on-site (i.e. for use in a purification process). If CO_2 was used on-site, provide the information in paragraphs (b)(17)(i) and (ii) of this section.

(i) The annual amount of CO_2 captured for use in the on-site process.

(ii) The method used to determine the amount of CO_2 captured.

[75 FR 66465, Oct. 28, 2010, as amended at 78 FR 71959, Nov. 29, 2013]

§ 98.197 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section.

(a) Annual operating hours in calendar year.

(b) Records of all analyses (e.g. chemical composition of lime products, by type) and calculations conducted.

§ 98.198 Definitions.

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

TABLE S–1 TO SUBPART S OF PART 98—BASIC PARAMETERS FOR THE CALCULATION OF EMISSION FACTORS FOR LIME PRODUCTION

Variable	Stoichiometric ratio
SR_{CaO}	0.7848
SR_{MgO}	1.0918

Subpart T—Magnesium Production

SOURCE: 75 FR 39761, July 12, 2010, unless otherwise noted.

§ 98.200 Definition of source category.

The magnesium production and processing source category consists of the following processes:

(a) Any process in which magnesium metal is produced through smelting (including electrolytic smelting), refining, or remelting operations.

(b) Any process in which molten magnesium is used in alloying, casting, drawing, extruding, forming, or rolling operations.

§ 98.201 Reporting threshold.

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

§ 98.202 GHGs to report.

(a) You must report emissions of the following gases in metric tons per year resulting from their use as cover gases or carrier gases in magnesium production or processing:

(1) Sulfur hexafluoride (SF_6).

(2) HFC–134a.

(3) The fluorinated ketone, FK 5–1–12.

(4) Carbon dioxide (CO_2).

(5) Any other GHGs (as defined in § 98.6).

(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the CO_2, N_2O, and CH_4 emissions from each combustion unit by following the requirements of subpart C.

§ 98.203 Calculating GHG emissions.

(a) Calculate the mass of each GHG emitted from magnesium production or processing over the calendar year using either Equation T–1 or Equation T–2 of this section, as appropriate. Both of these equations equate emissions of cover gases or carrier gases to consumption of cover gases or carrier gases.

(1) To estimate emissions of cover gases or carrier gases by monitoring changes in container masses and inventories, emissions of each cover gas or carrier gas shall be estimated using Equation T–1 of this section:

$$E_x = \left(I_{B,x} - I_{E,x} + A_x - D_x\right) * 0.001 \qquad \text{(Eq. T-1)}$$

Where:

E_X = Emissions of each cover gas or carrier gas, X, in metric tons over the reporting year.

$I_{B,x}$ = Inventory of each cover gas or carrier gas stored in cylinders or other containers at the beginning of the year, including heels, in kg.

$I_{E,x}$ = Inventory of each cover gas or carrier gas stored in cylinders or other containers at the end of the year, including heels, in kg.

A_X = Acquisitions of each cover gas or carrier gas during the year through purchases or other transactions, including heels in cylinders or other containers returned to the magnesium production or processing facility, in kg.

D_X = Disbursements of each cover gas or carrier gas to sources and locations outside the facility through sales or other transactions during the year, including heels in cylinders or other containers returned by the magnesium production or processing facility to the gas supplier, in kg.

0.001 = Conversion factor from kg to metric tons

X = Each cover gas or carrier gas that is a GHG.

(2) To estimate emissions of cover gases or carrier gases by monitoring changes in the masses of individual containers as their contents are used, emissions of each cover gas or carrier gas shall be estimated using Equation T–2 of this section:

$$E_{GHG} = \sum_{p=1}^{n} Q_p * 0.001 \qquad \text{(Eq. T-2)}$$

Where:

E_{GHG} = Emissions of each cover gas or carrier gas, X, over the reporting year (metric tons).

Q_p = The mass of the cover or carrier gas consumed (kg) over the container-use period p, from Equation T–3 of this section.

n = The number of container-use periods in the year.

0.001 = Conversion factor from kg to metric tons.

X = Each cover gas or carrier gas that is a GHG.

(b) For purposes of Equation T–2 of this section, the mass of the cover gas used over the period p for an individual container shall be estimated by using Equation T–3 of this section:

$$Q_p = M_B - M_E \qquad \text{(Eq. T-3)}$$

Where:

Q_p = The mass of the cover or carrier gas consumed (kg) over the container-use period p (*e.g.*, one month).

M_B = The mass of the container's contents (kg) at the beginning of period p.

M_E = The mass of the container's contents (kg) at the end of period p.

(c) If a facility has mass flow controllers (MFC) and the capacity to track and record MFC measurements to estimate total gas usage, the mass of each cover or carrier gas monitored may be used as the mass of cover or carrier gas consumed (Q_p), in kg for period p in Equation T–2 of this section.

§ 98.204 Monitoring and QA/QC requirements.

(a) For calendar year 2011 monitoring, the facility may submit a request to the Administrator to use one or more best available monitoring methods as listed in § 98.3(d)(1)(i) through (iv). The request must be submitted no later than October 12, 2010 and must contain the information in § 98.3(d)(2)(ii). To obtain approval, the request must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2011. The use of best available monitoring methods will not be approved beyond December 31, 2011.

(b) Emissions (consumption) of cover gases and carrier gases may be estimated by monitoring the changes in container weights and inventories using Equation T–1 of this subpart, by monitoring the changes in individual container weights as the contents of each container are used using Equations T–2 and T–3 of this subpart, or by monitoring the mass flow of the pure cover gas or carrier gas into the gas distribution system. Emissions must be estimated at least annually.

(c) When estimating emissions by monitoring the mass flow of the pure cover gas or carrier gas into the gas distribution system, you must use gas flow meters, or mass flow controllers, with an accuracy of 1 percent of full scale or better.

(d) When estimating emissions using Equation T–1 of this subpart, you must ensure that all the quantities required by Equation T–1 of this subpart have been measured using scales or load cells with an accuracy of 1 percent of full scale or better, accounting for the tare weights of the containers. You may accept gas masses or weights provided by the gas supplier *e.g.*, for the contents of containers containing new gas or for the heels remaining in containers returned to the gas supplier) if the supplier provides documentation verifying that accuracy standards are met; however you remain responsible for the accuracy of these masses or weights under this subpart.

(e) When estimating emissions using Equations T–2 and T–3 of this subpart, you must monitor and record container identities and masses as follows:

(1) Track the identities and masses of containers leaving and entering storage with check-out and check-in sheets and procedures. The masses of cylinders returning to storage shall be measured immediately before the cylinders are put back into storage.

(2) Ensure that all the quantities required by Equations T–2 and T–3 of this subpart have been measured using scales or load cells with an accuracy of 1 percent of full scale or better, accounting for the tare weights of the containers. You may accept gas masses or weights provided by the gas supplier *e.g.*, for the contents of cylinders containing new gas or for the heels remaining in cylinders returned to the gas supplier) if the supplier provides documentation verifying that accuracy standards are met; however, you remain responsible for the accuracy of these masses or weights under this subpart.

(f) All flowmeters, scales, and load cells used to measure quantities that are to be reported under this subpart shall be calibrated using calibration procedures specified by the flowmeter, scale, or load cell manufacturer. Calibration shall be performed prior to the first reporting year. After the initial calibration, recalibration shall be performed at the minimum frequency specified by the manufacturer.

§ 98.205 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emission calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter will be used in the calculations as specified in paragraph (b) of this section.

(b) Replace missing data on the emissions of cover or carrier gases by multiplying magnesium production during the missing data period by the average cover or carrier gas usage rate from the most recent period when operating conditions were similar to those for the period for which the data are missing. Calculate the usage rate for each cover or carrier gas using Equation T–4 of this section:

$$R_{GHG} = C_{GHG} / Mg * 0.001 \qquad \text{(Eq. T-4)}$$

Where:

R_{GHG} = The usage rate for a particular cover or carrier gas over the period of comparable operation (metric tons gas/metric ton Mg).

C_{GHG} = The consumption of that cover or carrier gas over the period of comparable operation (kg).

Mg = The magnesium produced or fed into the process over the period of comparable operation (metric tons).

0.001 = Conversion factor from kg to metric tons.

(c) If the precise before and after weights are not available, it should be assumed that the container was emptied in the process (*i.e.*, quantity purchased should be used, less heel).

§ 98.206 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must include the following information at the facility level:

(a) Emissions of each cover or carrier gas in metric tons.

(b) Types of production processes at the facility (*e.g.*, primary, secondary, die casting).

(c) Amount of magnesium produced or processed in metric tons for each process type. This includes the output of primary and secondary magnesium production processes and the input to magnesium casting processes.

(d) Cover and carrier gas flow rate (*e.g.*, standard cubic feet per minute) for each production unit and composition in percent by volume.

(e) For any missing data, you must report the length of time the data were missing for each cover gas or carrier gas, the method used to estimate emissions in their absence, and the quantity of emissions thereby estimated.

(f) The annual cover gas usage rate for the facility for each cover gas, excluding the carrier gas (kg gas/metric ton Mg).

(g) If applicable, an explanation of any change greater than 30 percent in the facility's cover gas usage rate (*e.g.*, installation of new melt protection technology or leak discovered in the cover gas delivery system that resulted in increased emissions).

(h) A description of any new melt protection technologies adopted to account for reduced or increased GHG emissions in any given year.

§ 98.207 Records that must be retained.

In addition to the records specified in § 98.3(g), you must retain the following information at the facility level:

(a) Check-out and weigh-in sheets and procedures for gas cylinders.

(b) Accuracy certifications and calibration records for scales including the method or manufacturer's specification used for calibration.

(c) Residual gas amounts (heel) in cylinders sent back to suppliers.

(d) Records, including invoices, for gas purchases, sales, and disbursements for all GHGs.

§ 98.208 Definitions.

All terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part. Additionally, some sector-specific definitions are provided below:

Carrier gas means the gas with which cover gas is mixed to transport and dilute the cover gas thus maximizing its efficient use. Carrier gases typically include CO_2, N_2, and/or dry air.

Cover gas means SF_6, HFC–134a, fluorinated ketone (FK 5–1–12) or other gas used to protect the surface of molten magnesium from rapid oxidation and burning in the presence of air. The molten magnesium may be the surface of a casting or ingot production operation or the surface of a crucible of molten magnesium that feeds a casting operation.

Subpart U—Miscellaneous Uses of Carbonate

§ 98.210 Definition of the source category.

(a) This source category includes any equipment that uses carbonates listed in Table U–1 in manufacturing processes that emit carbon dioxide. Table U–1 includes the following carbonates: limestone, dolomite, ankerite, magnesite, siderite, rhodochrosite, or sodium carbonate. Facilities are considered to emit CO_2 if they consume at least 2,000 tons per year of carbonates heated to a temperature sufficient to allow the calcination reaction to occur.

(b) This source category does not include equipment that uses carbonates or carbonate containing minerals that are consumed in the production of cement, glass, ferroalloys, iron and steel, lead, lime, phosphoric acid, pulp and paper, soda ash, sodium bicarbonate, sodium hydroxide, or zinc.

(c) This source category does not include carbonates used in sorbent technology used to control emissions from stationary fuel combustion equipment. Emissions from carbonates used in sorbent technology are reported under 40 CFR 98, subpart C (Stationary Fuel Combustion Sources).

§ 98.211 Reporting threshold.

You must report GHG emissions from miscellaneous uses of carbonate if your facility uses carbonates as defined in § 98.210 of this subpart and the facility meets the requirements of either § 98.2(a)(1) or (a)(2).

§ 98.212 GHGs to report.

You must report CO_2 process emissions from all miscellaneous carbonate use at your facility as specified in this subpart.

§ 98.213 Calculating GHG emissions.

You must determine CO_2 process emissions from carbonate use in accordance with the procedures specified in either paragraphs (a) or (b) of this section.

(a) Calculate the process emissions of CO_2 using calcination fractions with Equation U–1 of this section.

$$E_{CO_2} = \sum_{i=1}^{n} M_i * EF_i * F_i * \frac{2000}{2205} \qquad \text{(Eq. U-1)}$$

Where:

E_{CO2} = Annual CO_2 mass emissions from consumption of carbonates (metric tons).

M_i = Annual mass of carbonate type i consumed (tons).

EF_i = Emission factor for the carbonate type i, as specified in Table U–1 to this subpart, metric tons CO_2/metric ton carbonate consumed.

F_i = Fraction calcination achieved for each particular carbonate type i (decimal fraction). As an alternative to measuring the calcination fraction, a value of 1.0 can be used.

n = Number of carbonate types.

2000/2205 = Conversion factor to convert tons to metric tons.

(b) Calculate the process emissions of CO_2 using actual mass of output carbonates with Equation U–2 of this section.

$$E_{CO_2} = \left[\sum_{k=1}^{m} \left(M_k * EF_k\right) - \sum_{j=1}^{n} \left(M_j * EF_j\right) \right] * \frac{2000}{2205} \qquad \text{(Eq. U-2)}$$

Where:

E_{CO2} = Annual CO_2 mass emissions from consumption of carbonates (metric tons).

M_k = Annual mass of input carbonate type k (tons).

EF_k = Emission factor for the carbonate type k, as specified in Table U–1 of this subpart (metric tons CO_2/metric ton carbonate input).

M_j = Annual mass of output carbonate type j (tons).

EF_j = Emission factor for the output carbonate type j, as specified in Table U–1 of this subpart (metric tons CO_2/metric ton carbonate input).

m = Number of input carbonate types.

n = Number of output carbonate types.

§98.214 Monitoring and QA/QC requirements.

(a) The annual mass of carbonate consumed (for Equation U–1 of this subpart) or carbonate inputs (for Equation U–2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or weigh belt feeders.

(b) The annual mass of carbonate outputs (for Equation U–2 of this subpart) must be determined annually from monthly measurements using the same plant instruments used for accounting purposes including purchase records or direct measurement, such as weigh hoppers or belt weigh feeders.

(c) If you follow the procedures of §98.213(a), as an alternative to assuming a calcination fraction of 1.0, you can determine on an annual basis the calcination fraction for each carbonate consumed based on sampling and chemical analysis using a suitable method such as using an x-ray fluorescence standard method or other enhanced industry consensus standard method published by an industry consensus standard organization (e.g., ASTM, ASME, etc.).

§98.215 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraph (b) of this section. You must document and keep records of the procedures used for all such estimates.

(b) For each missing value of monthly carbonate consumed, monthly carbonate output, or monthly carbonate input, the substitute data value must be the best available estimate based on the all available process data or data used for accounting purposes.

§98.216 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) through (g) of this section at the facility level, as applicable.

(a) Annual CO_2 emissions from miscellaneous carbonate use (metric tons).

(b) Annual mass of each carbonate type consumed (tons).

(c) Measurement method used to determine the mass of carbonate.

(d) Method used to calculate emissions.

(e) If you followed the calculation method of §98.213(b)(1)(i), you must report the information in paragraphs (e)(1) through (e)(3) of this section.

(1) Annual carbonate consumption by carbonate type (tons).

(2) Annual calcination fractions used in calculations.

(3) If you determined the calcination fraction, indicate which standard method was used.

(f) If you followed the calculation method of §98.213(b)(1)(ii), you must report the information in paragraphs (f)(1) and (f)(2) of this section.

(1) Annual carbonate input by carbonate type (tons).

(2) Annual carbonate output by carbonate type (tons).

(g) Number of times in the reporting year that missing data procedures were followed to measure carbonate consumption, carbonate input or carbonate output (months).

§98.217 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) through (d) of this section:

(a) Monthly carbonate consumption (by carbonate type in tons).

(b) You must document the procedures used to ensure the accuracy of the monthly measurements of carbonate consumption, carbonate input or carbonate output including, but not limited to, calibration of weighing equipment and other measurement devices.

(c) Records of all analyses conducted to meet the requirements of this rule.

(d) Records of all calculations conducted.

§ 98.218 Definitions.

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

TABLE U–1 TO SUBPART U OF PART 98—CO_2 EMISSION FACTORS FOR COMMON CARBONATES

Mineral name—carbonate	CO_2 emission factor (tons CO_2/ton carbonate)
Limestone—$CaCO_3$	0.43971
Magnesite—$MgCO_3$	0.52197
Dolomite—$CaMg(CO_3)_2$	0.47732
Siderite—$FeCO_3$	0.37987
Ankerite—$Ca(Fe, Mg, Mn)(CO_3)_2$	0.47572
Rhodochrosite—$MnCO_3$	0.38286
Sodium Carbonate/Soda Ash—Na_2CO_3	0.41492

Subpart V—Nitric Acid Production

§ 98.220 Definition of source category.

A nitric acid production facility uses one or more trains to produce weak nitric acid (30 to 70 percent in strength). A nitric acid train produces weak nitric acid through the catalytic oxidation of ammonia.

§ 98.221 Reporting threshold.

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

§ 98.222 GHGs to report.

(a) You must report N_2O process emissions from each nitric acid train as required by this subpart.

(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit by following the requirements of subpart C.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71959, Nov. 29, 2013]

§ 98.223 Calculating GHG emissions.

(a) You must determine annual N_2O process emissions from each nitric acid train according to paragraphs (a)(1) or (a)(2) of this section.

(1) Use a site-specific emission factor and production data according to paragraphs (b) through (i) of this section.

(2) Request Administrator approval for an alternative method of determining N_2O emissions according to paragraphs (a)(2)(i) and (a)(2)(ii) of this section.

(i) You must submit the request within 45 days following promulgation of this subpart or within the first 30 days of each subsequent reporting year.

(ii) If the Administrator does not approve your requested alternative method within 150 days of the end of the reporting year, you must determine the N_2O emissions for the current reporting period using the procedures specified in paragraph (a)(1) of this section.

(b) You must conduct an annual performance test for each nitric acid train according to paragraphs (b)(1) through (3) of this section.

(1) You must conduct the performance test at the absorber tail gas vent, referred to as the test point, for each nitric acid train according to § 98.224(b) through (f). If multiple nitric acid trains exhaust to a common abatement technology and/or emission point, you must sample each process in the ducts before the emissions are combined, sample each process when only one process is operating, or sample the combined emissions when multiple processes are operating and base the site-specific emission factor on the combined production rate of the multiple nitric acid trains.

(2) You must conduct the performance test under normal process operating conditions.

(3) You must measure the production rate during the performance test and calculate the production rate for the test period in tons (100 percent acid basis) per hour.

(c) Using the results of the performance test in paragraph (b) of this section, you must calculate an average site-specific emission factor for each nitric acid train ''t'' according to Equation V–1 of this section:

$$EF_{N2Ot} = \frac{\sum_{1}^{n} \frac{C_{N2O} * 1.14 \times 10^{-7} * Q}{P}}{n} \quad \text{(Eq. V-1)}$$

where:

EF_{N_2Ot} = Average site-specific N_2O emissions factor for nitric acid train ''t'' (lb N_2O/ton nitric acid produced, 100 percent acid basis).

C_{N2O} = N_2O concentration for each test run during the performance test (ppm N_2O).

1.14×10^{-7} = Conversion factor (lb/dscf-ppm N_2O).

Q = Volumetric flow rate of effluent gas for each test run during the performance test (dscf/hr).

P = Production rate for each test run during the performance test (tons nitric acid produced per hour, 100 percent acid basis).

n = Number of test runs.

(d) If nitric acid train ''t'' exhausts to any N_2O abatement technology ''N'', you must determine the destruction efficiency for each N_2O abatement technology ''N'' according to paragraphs (d)(1), (2), or (3) of this section.

(1) Use the manufacturer's specified destruction efficiency.

(2) Estimate the destruction efficiency through process knowledge. Examples of information that could constitute process knowledge include calculations based on material balances, process stoichiometry, or previous test results provided the results are still relevant to the current vent stream conditions. You must document how process knowledge (if applicable) was used to determine the destruction efficiency.

(3) Calculate the destruction efficiency by conducting an additional performance test on the emissions stream following the N_2O abatement technology.

(e) If nitric acid train ''t'' exhausts to any N_2O abatement technology ''N'', you must determine the annual amount of nitric acid produced on nitric acid train ''t'' while N_2O abatement technology ''N'' is operating according to §98.224(f). Then you must calculate the abatement utilization factor for each N_2O abatement technology ''N'' for each nitric acid train ''t'' according to Equation V–2 of this section.

$$AF_{t,N} = \frac{P_{t,N}}{P_t} \quad \text{(Eq. V-2)}$$

where:

$AF_{t,N}$ = Abatement utilization factor of N_2O abatement technology ''N'' at nitric acid train ''t'' (fraction of annual production that abatement technology is operating).

P_t = Total annual nitric acid production from nitric acid train ''t'' (ton acid produced, 100 percent acid basis).

$P_{t,N}$ = Annual nitric acid production from nitric acid train ''t'' during which N_2O abatement technology ''N'' was operational (ton acid produced, 100 percent acid basis).

(f) [Reserved]

(g) You must calculate N_2O emissions for each nitric acid train ''t'' according to paragraph (g)(1), (g)(2), (g)(3), or (g)(4) of this section.

(1) If nitric acid train ''t'' exhausts to one N_2O abatement technology ''N'' after the test point, you must use the emissions factor (determined in Equation V–1 of this section), the destruction efficiency (determined in paragraph (d) of this section), the annual nitric acid production (determined in paragraph (i) of this section), and the abatement utilization factor (determined in paragraph (e) of this section) according to Equation V–3a of this section:

$$E_{N2Ot} = \frac{EF_{N20t} * P_t}{2205} * \left(1-\left(DF * AF\right)\right) \qquad \text{(Eq. V-3a)}$$

where:

E_{N_2Ot} = Annual N_2O mass emissions from nitric acid train “t” according to this Equation V–3a (metric tons).

EF_{N_2Ot} = Average site-specific N_2O emissions factor for nitric acid train ”t” (lb N_2O/ton acid produced, 100 percent acid basis).

P_t = Annual nitric acid production from nitric acid train “t” (ton acid produced, 100 percent acid basis).

DF = Destruction efficiency of N_2O abatement technology N that is used on nitric acid train “t” (decimal fraction of N_2O removed from vent stream).

AF = Abatement utilization factor of N_2O abatement technology “N” for nitric acid train “t” (decimal fraction of annual production during which abatement technology is operating).

2205 = Conversion factor (lb/metric ton).

(2) If multiple N_2O abatement technologies are located in series after your test point, you must use the emissions factor (determined in Equation V–1 of this section), the destruction efficiency (determined in paragraph (d) of this section), the annual nitric acid production (determined in paragraph (i) of this section), and the abatement utilization factor (determined in paragraph (e) of this section), according to Equation V–3b of this section:

$$E_{N2Ot} = \frac{EF_{N20,t} * P_t}{2205} * \left(1-\left(DF_1 * AF_1\right)\right) * \left(1-\left(DF_2 * AF_2\right)\right) * \ldots * \left(1-\left(DF_{\text{N}} * AF_{\text{N}}\right)\right) \qquad \text{(Eq. V-3b)}$$

where:

E_{N_2Ot} = Annual N_2O mass emissions from nitric acid train “t” according to this Equation V–3b (metric tons).

$EF_{N2O,t}$ = N_2O emissions factor for nitric acid train “t” (lb N_2O/ton nitric acid produced).

P_t = Annual nitric acid produced from nitric acid train “t” (ton acid produced, 100 percent acid basis).

DF_1 = Destruction efficiency of N_2O abatement technology 1 (decimal fraction of N_2O removed from vent stream).

AF_1 = Abatement utilization factor of N_2O abatement technology 1 (decimal fraction of time that abatement technology 1 is operating).

DF_2 = Destruction efficiency of N_2O abatement technology 2 (decimal fraction of N_2O removed from vent stream).

AF_2 = Abatement utilization factor of N_2O abatement technology 2 (decimal fraction of time that abatement technology 2 is operating).

DF_N = Destruction efficiency of N_2O abatement technology N (decimal fraction of N_2O removed from vent stream).

AF_N = Abatement utilization factor of N_2O abatement technology N (decimal fraction of time that abatement technology N is operating).

2205 = Conversion factor (lb/metric ton).

N = Number of different N_2O abatement technologies.

(3) If multiple N_2O abatement technologies are located in parallel after your test point, you must use the emissions factor (determined in Equation V–1 of this section), the destruction efficiency (determined in paragraph (d) of this section), the annual nitric acid production (determined in paragraph (i) of this section), and the abatement utilization factor (determined in paragraph (e) of this section), according to Equation V–3c of this section:

$$E_{N2Ot} = \frac{EF_{N20,t} * P_t}{2205} * \sum_{1}^{N} \left(\left(1-\left(DF_N * AF_N\right)\right) * FC_N\right) \qquad \text{(Eq. V-3c)}$$

where:

E_{N_2Ot} = Annual N_2O mass emissions from nitric acid train "t" according to this Equation V–3c (metric tons).

$EF_{N2O,t}$ = N_2O emissions factor for nitric acid train "t" (lb N_2O/ton nitric acid produced).

P_t = Annual nitric acid produced from nitric acid train "t" (ton acid produced, 100 percent acid basis).

DF_N = Destruction efficiency of N_2O abatement technology "N" (decimal fraction of N_2O removed from vent stream).

AF_N = Abatement utilization factor of N_2O abatement technology "N" (decimal fraction of time that abatement technology "N" is operating).

FC_N = Fraction control factor of N_2O abatement technology "N" (decimal fraction of total emissions from nitric acid train "t" that are sent to abatement technology "N").

2205 = Conversion factor (lb/metric ton).

N = Number of different N_2O abatement technologies with a fraction control factor.

(4) If nitric acid train "t" does not exhaust to any N_2O abatement technology after the test point, you must use the emissions factor (determined in Equation V–1 of this section), and the annual nitric acid production (determined in paragraph (i) of this section) according to Equation V–3b of this section:

$$E_{N_2Ot} = \frac{EF_{N20t} * P_t}{2205} \qquad \text{(Eq. V-3d)}$$

where:

E_{N_2Ot} = Annual N_2O mass emissions from nitric acid train "t" according to this Equation V–3d (metric tons).

EF_{N_2Ot} = Average site-specific N_2O emissions factor for nitric acid train "t" (lb N_2O/ton acid produced, 100 percent acid basis).

P_t = Annual nitric acid production from nitric acid train "t" (ton acid produced, 100 percent acid basis).

2205 = Conversion factor (lb/metric ton).

(h) You must determine the annual nitric acid production emissions combined from all nitric acid trains at your facility using Equation V–4 of this section:

$$N_2O = \sum_{t=1}^{m} E_{N2Ot} \qquad \text{(Eq. V-4)}$$

Where:

N_2O = Annual process N_2O emissions from nitric acid production facility (metric tons).

E_{N_2Ot} = N_2O mass emissions per year for nitric acid train "t" (metric tons).

m = Number of nitric acid trains.

(i) You must determine the total annual amount of nitric acid produced on each nitric acid train "t" (tons acid produced, 100 percent acid basis), according to § 98.224(f).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66466, Oct. 28, 2010; 78 FR 71959, Nov. 29, 2013]

§ 98.224 Monitoring and QA/QC requirements.

(a) You must conduct a new performance test according to a test plan as specified in paragraphs (a)(1) through (3) of this section.

(1) Conduct the performance test annually. The test should be conducted at a point during the campaign which is representative of the average emissions rate from the nitric acid campaigns. Facilities must document the methods used to determine the representative point of the campaign when the performance test is conducted.

(2) Conduct the performance test when your nitric acid production process is changed, specifically when abatement equipment is installed.

(3) If you requested Administrator approval for an alternative method of determining N_2O emissions under § 98.223(a)(2), you must conduct the performance test if your request has not been approved by the Administrator within 150 days of the end of the reporting year in which it was submitted.

(b) You must measure the N_2O concentration during the performance test using one of the methods in paragraphs (b)(1) through (b)(3) of this section.

(1) EPA Method 320 at 40 CFR part 63, appendix A, Measurement of Vapor Phase Organic and Inorganic Emissions by Extractive Fourier Transform Infrared (FTIR) Spectroscopy.

(2) ASTM D6348–03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy (incorporated by reference in § 98.7).

(3) An equivalent method, with Administrator approval.

(c) You must determine the production rate(s) (100 percent acid basis) from each nitric acid train during the performance test according to paragraphs (c)(1) or (2) of this section.

(1) Direct measurement of production and concentration (such as using flow meters, weigh scales, for production and concentration measurements).

(2) Existing plant procedures used for accounting purposes (i.e. dedicated tank-level and acid concentration measurements).

(d) You must determine the volumetric flow rate during the performance test in conjunction with the applicable EPA methods in 40 CFR part 60, appendices A–1 through A–4. Conduct three emissions test runs of 1 hour each. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (d)(1) through (d)(3) of this section.

(1) Analysis of samples, determination of emissions, and raw data.

(2) All information and data used to derive the emissions factor(s).

(3) The production rate during each test and how it was determined.

(e) You must determine the total monthly amount of nitric acid produced. You must also determine the monthly amount of nitric acid produced while N_2O abatement technology is operating from each nitric acid train. These monthly amounts are determined according to the methods in paragraphs (c)(1) or (2) of this section.

(f) You must determine the annual amount of nitric acid produced. You must also determine the annual amount of nitric acid produced while N_2O abatement technology is operating for each nitric acid train. These annual amounts are determined by summing the respective monthly nitric acid quantities determined in paragraph (e) of this section.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66467, Oct. 28, 2010; 78 FR 71960, Nov. 29, 2013]

§ 98.225 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of nitric acid production, the substitute data shall be the best available estimate based on all available process data or data used for accounting purposes (such as sales records).

(b) For missing values related to the performance test, including emission factors, production rate, and N_2O concentration, you must conduct a new performance test according to the procedures in § 98.224 (a) through (d).

§ 98.226 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (p) of this section.

(a) Nitric Acid train identification number.

(b) Annual process N_2O emissions from each nitric acid train (metric tons).

(c) [Reserved]

(d) Annual nitric acid production from each nitric acid train during which N_2O abatement technology is operating (ton acid produced, 100 percent acid basis).

(e) Annual nitric acid production from the nitric acid facility (tons, 100 percent acid basis).

(f) Number of nitric acid trains.

(g) Number of different N_2O abatement technologies per nitric acid train "t".

(h) Abatement technologies used (if applicable).

(i) Abatement technology destruction efficiency for each abatement technology (percent destruction).

(j) Abatement utilization factor for each abatement technology (fraction of annual production that abatement technology is operating).

(k) Type of nitric acid process used for each nitric acid train (low, medium, high, or dual pressure).

(l) Number of times in the reporting year that missing data procedures were followed to measure nitric acid production (months).

(m) If you conducted a performance test and calculated a site-specific emissions factor according to § 98.223(a)(1), each annual report must also contain the information specified in paragraphs (m)(1) through (7) of this section.

(1) Emission factor calculated for each nitric acid train (lb N_2O/ton nitric acid, 100 percent acid basis).

(2) Test method used for performance test.

(3) Production rate per test run during performance test (tons nitric acid produced/hr, 100 percent acid basis).

(4) N_2O concentration per test run during performance test (ppm N_2O).

(5) Volumetric flow rate per test run during performance test (dscf/hr).

(6) Number of test runs during performance test.

(7) Number of times in the reporting year that a performance test had to be repeated (number).

(n) If you requested Administrator approval for an alternative method of determining N_2O emissions under § 98.223(a)(2), each annual report must also contain the information specified in paragraphs (n)(1) through (4) of this section.

(1) Name of alternative method.

(2) Description of alternative method.

(3) Request date.

(4) Approval date.

(o) [Reserved]

(p) Fraction control factor for each abatement technology (percent of total emissions from the nitric acid train that are sent to the abatement technology) if Equation V–3c is used.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66468, Oct. 28, 2010; 75 FR 79157, Dec. 17, 2010; 78 FR 71960, Nov. 29, 2013]

§ 98.227 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the records specified in paragraphs (a) through (g) of this section for each nitric acid production facility:

(a) Records of significant changes to process.

(b) Documentation of how process knowledge was used to estimate abatement technology destruction efficiency (if applicable).

(c) Performance test reports.

(d) Number of operating hours in the calendar year for each nitric acid train (hours).

(e) Annual nitric acid permitted production capacity (tons).

(f) Measurements, records, and calculations used to determine reported parameters.

(g) Documentation of the procedures used to ensure the accuracy of the measurements of all reported parameters, including but not limited to, calibration of weighing equipment, flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.228 Definitions.

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

Subpart W—Petroleum and Natural Gas Systems

SOURCE: 75 FR 74488, Nov. 30, 2010, unless otherwise noted.

§ 98.230 Definition of the source category.

(a) This source category consists of the following industry segments:

(1) *Offshore petroleum and natural gas production*. Offshore petroleum and natural gas production is any platform structure, affixed temporarily or permanently to offshore submerged lands, that houses equipment to extract hydrocarbons from the ocean or lake floor and that processes and/or transfers

such hydrocarbons to storage, transport vessels, or onshore. In addition, offshore production includes secondary platform structures connected to the platform structure via walkways, storage tanks associated with the platform structure and floating production and storage offloading equipment (FPSO). This source category does not include reporting of emissions from offshore drilling and exploration that is not conducted on production platforms.

(2) *Onshore petroleum and natural gas production.* Onshore petroleum and natural gas production means all equipment on a single well-pad or associated with a single well-pad (including but not limited to compressors, generators, dehydrators, storage vessels, and portable non-self-propelled equipment which includes well drilling and completion equipment, workover equipment, gravity separation equipment, auxiliary non-transportation-related equipment, and leased, rented or contracted equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of petroleum and/or natural gas (including condensate). This equipment also includes associated storage or measurement vessels and all enhanced oil recovery (EOR) operations using CO_2 or natural gas injection, and all petroleum and natural gas production equipment located on islands, artificial islands, or structures connected by a causeway to land, an island, or an artificial island.

(3) *Onshore natural gas processing.* Natural gas processing means the separation of natural gas liquids (NGLs) or non-methane gases from produced natural gas, or the separation of NGLs into one or more component mixtures. Separation includes one or more of the following: forced extraction of natural gas liquids, sulfur and carbon dioxide removal, fractionation of NGLs, or the capture of CO_2 separated from natural gas streams. This segment also includes all residue gas compression equipment owned or operated by the natural gas processing plant. This industry segment includes processing plants that fractionate gas liquids, and processing plants that do not fractionate gas liquids but have an annual average throughput of 25 MMscf per day or greater.

(4) *Onshore natural gas transmission compression.* Onshore natural gas transmission compression means any stationary combination of compressors that move natural gas from production fields, natural gas processing plants, or other transmission compressors through transmission pipelines to natural gas distribution pipelines, LNG storage facilities, or into underground storage. In addition, a transmission compressor station includes equipment for liquids separation, and tanks for the storage of water and hydrocarbon liquids. Residue (sales) gas compression that is part of onshore natural gas processing plants are included in the onshore natural gas processing segment and are excluded from this segment.

(5) *Underground natural gas storage.* Underground natural gas storage means subsurface storage, including depleted gas or oil reservoirs and salt dome caverns that store natural gas that has been transferred from its original location for the primary purpose of load balancing (the process of equalizing the receipt and delivery of natural gas); natural gas underground storage processes and operations (including compression, dehydration and flow measurement, and excluding transmission pipelines); and all the wellheads connected to the compression units located at the facility that inject and recover natural gas into and from the underground reservoirs.

(6) *Liquefied natural gas (LNG) storage.* LNG storage means onshore LNG storage vessels located above ground, equipment for liquefying natural gas, compressors to capture and re-liquefy boil-off-gas, re-condensers, and vaporization units for re-gasification of the liquefied natural gas.

(7) *LNG import and export equipment.* LNG import equipment means all onshore or offshore equipment that receives imported LNG via ocean transport, stores LNG, re-gasifies LNG, and delivers re-gasified natural gas to a natural gas transmission or distribution system. LNG export equipment

means all onshore or offshore equipment that receives natural gas, liquefies natural gas, stores LNG, and transfers the LNG via ocean transportation to any location, including locations in the United States.

(8) *Natural gas distribution.* Natural gas distribution means the distribution pipelines and metering and regulating equipment at metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that is operated as an independent municipally-owned distribution system. This segment also excludes customer meters and regulators, infrastructure, and pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

(b) [Reserved]

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80574, Dec. 23, 2011]

§ 98.231 Reporting threshold.

(a) You must report GHG emissions under this subpart if your facility contains petroleum and natural gas systems and the facility meets the requirements of § 98.2(a)(2). Facilities must report emissions from the onshore petroleum and natural gas production industry segment only if emission sources specified in paragraph § 98.232(c) emit 25,000 metric tons of CO_2 equivalent or more per year. Facilities must report emissions from the natural gas distribution industry segment only if emission sources specified in paragraph § 98.232(i) emit 25,000 metric tons of CO_2 equivalent or more per year.

(b) For applying the threshold defined in § 98.2(a)(2), natural gas processing facilities must also include owned or operated residue gas compression equipment.

§ 98.232 GHGs to report.

(a) You must report CO_2, CH_4, and N_2O emissions from each industry segment specified in paragraph (b) through (i) of this section, CO_2, CH_4, and N_2O emissions from each flare as specified in paragraph (b) through (i) of this section, and stationary and portable combustion emissions as applicable as specified in paragraph (k) of this section.

(b) For offshore petroleum and natural gas production, report CO_2, CH_4, and N_2O emissions from equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304. Offshore platforms do not need to report portable emissions.

(c) For an onshore petroleum and natural gas production facility, report CO_2, CH_4, and N_2O emissions from only the following source types on a single well-pad or associated with a single well-pad:

(1) Natural gas pneumatic device venting.

(2) [Reserved]

(3) Natural gas driven pneumatic pump venting.

(4) Well venting for liquids unloading.

(5) Gas well venting during well completions without hydraulic fracturing.

(6) Gas well venting during well completions with hydraulic fracturing.

(7) Gas well venting during well workovers without hydraulic fracturing.

(8) Gas well venting during well workovers with hydraulic fracturing.

(9) Flare stack emissions.

(10) Storage tanks vented emissions from produced hydrocarbons.

(11) Reciprocating compressor rod packing venting.

(12) Well testing venting and flaring.

(13) Associated gas venting and flaring from produced hydrocarbons.

(14) Dehydrator vents.

(15) [Reserved]

(16) EOR injection pump blowdown.

(17) Acid gas removal vents.

(18) EOR hydrocarbon liquids dissolved CO_2.

(19) Centrifugal compressor venting.

(20) [Reserved]

(21) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, pumps, flanges, and other equipment leak sources (such as instruments, loading arms, stuffing boxes, compressor seals, dump lever arms, and breather caps).

(22) You must use the methods in § 98.233(z) and report under this subpart

the emissions of CO_2, CH_4, and N_2O from stationary or portable fuel combustion equipment that cannot move on roadways under its own power and drive train, and that is located at an onshore petroleum and natural gas production facility as defined in § 98.238. Stationary or portable equipment are the following equipment, which are integral to the extraction, processing, or movement of oil or natural gas: well drilling and completion equipment, workover equipment, natural gas dehydrators, natural gas compressors, electrical generators, steam boilers, and process heaters.

(d) For onshore natural gas processing, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Dehydrator vents.

(5) Acid gas removal vents.

(6) Flare stack emissions.

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(e) For onshore natural gas transmission compression, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Transmission storage tanks.

(4) Blowdown vent stacks.

(5) Natural gas pneumatic device venting.

(6) [Reserved]

(7) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(f) For underground natural gas storage, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Natural gas pneumatic device venting.

(4) [Reserved]

(5) Equipment leaks from valves, connectors, open ended lines, pressure relief valves, and meters.

(g) For LNG storage, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Equipment leaks from valves; pump seals; connectors; vapor recovery compressors, and other equipment leak sources.

(h) LNG import and export equipment, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Reciprocating compressor rod packing venting.

(2) Centrifugal compressor venting.

(3) Blowdown vent stacks.

(4) Equipment leaks from valves, pump seals, connectors, vapor recovery compressors, and other equipment leak sources.

(i) For natural gas distribution, report CO_2, CH_4, and N_2O emissions from the following sources:

(1) Meters, regulators, and associated equipment at above grade transmission-distribution transfer stations, including equipment leaks from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines.

(2) Equipment leaks from vaults at below grade transmission-distribution transfer stations.

(3) Meters, regulators, and associated equipment at above grade metering-regulating station.

(4) Equipment leaks from vaults at below grade metering-regulating stations.

(5) Pipeline main equipment leaks.

(6) Service line equipment leaks.

(7) Report under subpart W of this part the emissions of CO_2, CH_4, and N_2O emissions from stationary fuel combustion sources following the methods in § 98.233(z)

(j) [Reserved]

(k) Report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary fuel combustion unit by following the requirements of subpart C except for facilities under onshore petroleum and natural gas production and natural gas distribution. Onshore petroleum and natural gas production facilities must report stationary and portable combustion emissions as specified in paragraph (c) of this section. Natural gas distribution facilities must report stationary combustion emissions as specified in paragraph (i) of this section.

(l) You must report under subpart PP of this part (Suppliers of Carbon Dioxide), CO_2 emissions captured and transferred off site by following the requirements of subpart PP.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80574, Dec. 23, 2011]

§ 98.233 Calculating GHG emissions.

You must calculate and report the annual GHG emissions as prescribed in this section. For actual conditions, reporters must use average atmospheric conditions or typical operating conditions as applicable to the respective monitoring methods in this section.

(a) *Natural gas pneumatic device venting.* Calculate CH_4 and CO_2 emissions from continuous high bleed, continuous low bleed, and intermittent bleed natural gas pneumatic devices using Equation W–1 of this section.

$$Mass_{t,i} = Count_t * EF_t * GHG_i * Conv_i * T_t \qquad \text{(Eq. W-1)}$$

Where:

$Mass_{t,i}$ = Annual total mass GHG emissions in metric tons CO_2e per year from a natural gas pneumatic device vent of type "t", for GHG_i.

$Count_t$ = Total number of natural gas pneumatic devices of type "t" (continuous high bleed, continuous low bleed, intermittent bleed) as determined in paragraph (a)(1), (a)(2), and (a)(3) of this section.

EF_t = Population emission factors for natural gas pneumatic device venting listed in Tables W–1A, W–3, and W–4 of this subpart for onshore petroleum and natural gas production, onshore natural gas transmission compression, and underground natural gas storage facilities, respectively.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG_i, CH_4, or CO_2, in natural gas as defined in paragraph (u)(2)(i) of this section and for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2.

$Conv_i$ = Conversion from standard cubic feet to metric tons CO_2e; 0.000479 for CH_4, and 0.00005262 for CO_2.

T_t = Average estimated number of hours in the operating year the devices, of each type t, were operational. Default is 8760 hours.

(1) For onshore petroleum and natural gas production, provide the total number of continuous high bleed, continuous low bleed, or intermittent bleed natural gas pneumatic devices of each type as follows:

(i) In the first calendar year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(ii) In the second consecutive year, for the total number of each type, you may count the total of each type, or count any percentage number of each type plus an engineering estimate based on best available data of the number not counted.

(iii) In the third consecutive calendar year, complete the count of all pneumatic devices, including any changes to equipment counted in prior years.

(iv) For the calendar year immediately following the third consecutive calendar year, and for calendar years thereafter, facilities must update the total count of pneumatic devices and adjust accordingly to reflect any modifications due to changes in equipment.

(2) For onshore natural gas transmission compression and underground natural gas storage, all natural gas pneumatic devices must be counted in the first year and updated every calendar year.

(3) For all industry segments, determine the type of pneumatic device using engineering estimates based on best available information.

(b) [Reserved]

(c) *Natural gas driven pneumatic pump venting.* Calculate CH_4 and CO_2 emissions from natural gas driven pneumatic pump venting using Equation W–2 of this section. Natural gas driven pneumatic pumps covered in paragraph (e) of this section do not have to report emissions under paragraph (c) of this section.

$$Mass_i = Count * EF * GHG_i * Conv_i * T \qquad \text{(Eq. W-2)}$$

Where:

$Mass_i$ = Annual total mass GHG emissions in metric tons CO_2e per year from all natural gas pneumatic pump venting, for $GHG_{i.}$

Count = Total number of natural gas pneumatic pumps.

EF = Population emissions factors for natural gas pneumatic pump venting listed in Tables W–1A of this subpart for onshore petroleum and natural gas production.

GHG_i = Concentration of GHG_i, CH_4, or CO_2, in produced natural gas as defined in paragraph (u)(2)(i) of this section.

$Conv_i$ = Conversion from standard cubic feet to metric tons CO_2e; 0.000479 for CH_4, and 0.00005262 for $CO_{2.}$

T = Average estimated number of hours in the operating year the pumps were operational. Default is 8760 hours.

(d) *Acid gas removal (AGR) vents.* For AGR vent (including processes such as amine, membrane, molecular sieve or other absorbents and adsorbents), calculate emissions for CO_2 only (not CH_4) vented directly to the atmosphere or through a flare, engine (*e.g.*, permeate from a membrane or de-adsorbed gas from a pressure swing adsorber used as fuel supplement), or sulfur recovery plant using any of the calculation methodologies described in paragraph (d) of this section, as applicable.

(1) *Calculation Methodology 1.* If you operate and maintain a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor, you must calculate CO_2 emissions under this subpart by following the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). Alternatively, you may follow the manufacturer's instructions or industry standard practice. If a CO_2 concentration monitor and volumetric flow rate monitor are not available, you may elect to install a CO_2 concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion). The calculation and reporting of CH_4 and N_2O emissions is not required as part of the Tier 4 requirements for AGRs.

(2) *Calculation Methodology 2.* If CEMS is not available but a vent meter is installed, use the CO_2 composition and annual volume of vent gas to calculate emissions using Equation W–3 of this section.

$$E_{a,CO2} = V_S * Vol_{CO2} \qquad \text{(Eq. W-3)}$$

where:

$E_{a,CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_S = Total annual volume of vent gas flowing out of the AGR unit in cubic feet per year at actual conditions as determined by flow meter using methods set forth in § 98.234(b). Alternatively, you may follow the manufacturer's instructions or industry standard practice for calibration of the vent meter.

Vol_{CO2} = Volume fraction of CO_2 content in vent gas out of the AGR unit as determined in (d)(6) of this section.

(3) *Calculation Methodology 3.* If CEMS or a vent meter is not installed, you may use the inlet or outlet gas flow rate of the acid gas removal unit to calculate emissions for CO_2 using Equations W–4A or W–4B of this section. If inlet gas flow rate is known, use Equation W–4A. If outlet gas flow rate is known, use Equation W–4B.

$$E_{a,CO2} = V_{in} * \left[\frac{Vol_I - Vol_O}{1 - Vol_O} \right] \qquad \text{(Eq. W-4A)}$$

$$E_{a,CO2} = V_{out} * \left[\frac{Vol_I - Vol_O}{1 - Vol_I} \right] \qquad \text{(Eq. W-4B)}$$

Where:

$E_{a,\ CO2}$ = Annual volumetric CO_2 emissions at actual conditions, in cubic feet per year.

V_{in} = Total annual volume of natural gas flow into the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section.

V_{out} = Total annual volume of natural gas flow out of the AGR unit in cubic feet per year at actual condition as determined using methods specified in paragraph (d)(5) of this section.

Vol_I = Volume fraction of CO_2 content in natural gas into the AGR unit as determined in paragraph (d)(7) of this section.

Vol_o = Volume fraction of CO_2 content in natural gas out of the AGR unit as determined in paragraph (d)(8) of this section.

(4) *Calculation Methodology 4.* If CEMS or a vent meter is not installed, you may calculate emissions using any standard simulation software packages, such as AspenTech HYSYS® and API 4679 AMINECalc, that uses the Peng-Robinson equation of state, and speciates CO_2 emissions. A minimum of the following determined for typical operating conditions over the calendar year by engineering estimate and process knowledge based on best available data must be used to characterize emissions:

(i) Natural gas feed temperature, pressure, and flow rate.

(ii) Acid gas content of feed natural gas.

(iii) Acid gas content of outlet natural gas.

(iv) Unit operating hours, excluding downtime for maintenance or standby.

(v) Exit temperature of natural gas.

(vi) Solvent pressure, temperature, circulation rate, and weight.

(5) Record the gas flow rate of the inlet and outlet natural gas stream of an AGR unit using a meter according to methods set forth in §98.234(b). If you do not have a continuous flow meter, either install a continuous flow meter or use an engineering calculation to determine the flow rate.

(6) If continuous gas analyzer is not available on the vent stack, either install a continuous gas analyzer or take quarterly gas samples from the vent gas stream to determine Vol_{CO2} according to methods set forth in §98.234(b).

(7) If a continuous gas analyzer is installed on the inlet gas stream, then the continuous gas analyzer results must be used. If continuous gas analyzer is not available, either install a continuous gas analyzer or take quarterly gas samples from the inlet gas stream to determine Vol_I according to methods set forth in §98.234(b).

(8) Determine volume fraction of CO_2 content in natural gas out of the AGR unit using one of the methods specified in paragraph (d)(8) of this section.

(i) If a continuous gas analyzer is installed on the outlet gas stream, then the continuous gas analyzer results must be used. If a continuous gas analyzer is not available, you may install a continuous gas analyzer.

(ii) If a continuous gas analyzer is not available or installed, quarterly gas samples may be taken from the outlet gas stream to determine Vol_O according to methods set forth in §98.234(b).

(iii) Use sales line quality specification for CO_2 in natural gas.

(9) Calculate CO_2 volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(10) Mass CO_2 emissions shall be calculated from volumetric CO_2 emissions using calculations in paragraph (v) of this section.

(11) Determine if emissions from the AGR unit are recovered and transferred

outside the facility. Adjust the emission estimated in paragraphs (d)(1) through (d)(10) of this section downward by the magnitude of emission recovered and transferred outside the facility.

(e) *Dehydrator vents.* For dehydrator vents, calculate annual CH_4, CO_2 and N_2O emissions using any of the calculation methodologies described in paragraph (e) of this section.

(1) *Calculation Methodology 1.* Calculate annual mass emissions from dehydrator vents with annual average daily throughput greater than or equal to 0.4 million standard cubic feet per day using a software program, such as AspenTech HYSYS® or GRI–GLYCalc, that uses the Peng-Robinson equation of state to calculate the equilibrium coefficient, speciates CH_4 and CO_2 emissions from dehydrators, and has provisions to include regenerator control devices, a separator flash tank, stripping gas and a gas injection pump or gas assist pump. A minimum of the following parameters determined by engineering estimate based on best available data must be used to characterize emissions from dehydrators:

(i) Feed natural gas flow rate.

(ii) Feed natural gas water content.

(iii) Outlet natural gas water content.

(iv) Absorbent circulation pump type (natural gas pneumatic/air pneumatic/electric).

(v) Absorbent circulation rate.

(vi) Absorbent type: including triethylene glycol (TEG), diethylene glycol (DEG) or ethylene glycol (EG).

(vii) Use of stripping gas.

(viii) Use of flash tank separator (and disposition of recovered gas).

(ix) Hours operated.

(x) Wet natural gas temperature and pressure.

(xi) Wet natural gas composition. Determine this parameter by selecting one of the methods described under paragraph (e)(1)(xi) of this section.

(A) Use the wet natural gas composition as defined in paragraph (u)(2)(i) or (u)(2)(ii) of this section.

(B) If wet natural gas composition cannot be determined using paragraph (u)(2)(i) or (u)(2)(ii) of this section, select a representative analysis.

(C) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as specified in §98.234(b) to sample and analyze wet natural gas composition.

(D) If only composition data for dry natural gas is available, assume the wet natural gas is saturated.

(2) *Calculation Methodology 2.* Calculate annual CH_4 and CO_2 emissions from glycol dehydrators with annual average daily throughput less than 0.4 million standard cubic feet per day using Equation W–5 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-5)}$$

where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factors for glycol dehydrators in thousand standard cubic feet per dehydrator per year. Use 73.4 for CH_4 and 3.21 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of glycol dehydrators with throughput less than 0.4 million standard cubic feet per day.

1000 = Conversion of EF_i in thousand standard cubic feet to standard cubic feet.

(3) Determine if dehydrator unit has vapor recovery. Adjust the emissions estimated in paragraphs (e)(1) or (e)(2) of this section downward by the magnitude of emissions captured.

(4) Calculate annual emissions from dehydrator vents to flares or regenerator fire-box/fire tubes as follows:

(A) Use the dehydrator vent volume and gas composition as determined in paragraphs (e)(1) and (e)(2) of this section.

(B) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine dehydrator vent emissions from the flare or regenerator combustion gas vent.

(5) Dehydrators that use desiccant shall calculate emissions from the

amount of gas vented from the vessel when it is depressurized for the desiccant refilling process using Equation W–6 of this section. Desiccant dehydrators covered in (e)(5) of this section do not have to report emissions under (i) of this section.

$$E_{s,n} = \frac{(H*D^2*P*P_2*\%G*N)}{(4*P_1*100)} \qquad \text{(Eq. W-6)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions in cubic feet.
H = Height of the dehydrator vessel (ft).
D = Inside diameter of the vessel (ft).
P_1 = Atmospheric pressure (psia).
P_2 = Pressure of the gas (psia).
P = pi (3.14).
%G = Percent of packed vessel volume that is gas.
N = Number of dehydrator openings in the calendar year.
100 = Conversion of %G to fraction.

(6) For glycol dehydrators, both CH_4 and CO_2 mass emissions shall be calculated from volumetric GHG_i emissions using calculations in paragraph (v) of this section. For dehydrators that use desiccant, both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(f) *Well venting for liquids unloadings.* Calculate CO_2 and CH_4 emissions from well venting for liquids unloading using one of the calculation methodologies described in paragraphs (f)(1), (f)(2) or (f)(3) of this section.

(1) *Calculation Methodology 1.* For at least one well of each unique well tubing diameter group and pressure group combination in each sub-basin category (see § 98.238 for the definitions of tubing diameter group, pressure group, and sub-basin category), where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing, a recording flow meter shall be installed on the vent line used to vent gas from the well (e.g., on the vent line off the wellhead separator or atmospheric storage tank) according to methods set forth in § 98.234(b). Calculate emissions from well venting for liquids unloading using Equation W–7 of this section.

$$E_{a,n} = \sum_{p=1}^{h} T_p FR \qquad \text{(Eq. W-7)}$$

Where:

$E_{a,n}$ = Annual natural gas emissions for all wells of the same tubing diameter group and pressure group combination in a sub-basin at actual conditions in cubic feet.
h = Total number of wells of the same tubing diameter group and pressure group combination in a sub-basin.
p = Wells 1 through h of the same tubing diameter group and pressure group combination in a sub-basin.
T_p = Cumulative amount of time in hours of venting for each well, p, of the same tubing diameter group and pressure group combination in a sub-basin during the year.
FR = Average flow rate in cubic feet per hour for all measured wells venting for the duration of the liquids unloading, under actual conditions as determined in paragraph (f)(1)(i) of this section.

(i) Determine the well vent average flow rate as specified under paragraph (f)(1)(i) of this section for at least one well in a unique well tubing diameter group and pressure group combination in each sub-basin category.

(A) The average flow rate per hour of venting is calculated for each unique tubing diameter group and pressure group combination in each sub-basin category by dividing the recorded total flow by the recorded time (in hours) for all measured liquid unloading events with venting to the atmosphere.

(B) This average flow rate per hour is applied to all wells in the same pressure group that have the same tubing diameter group, for the number of hours of venting these wells.

(C) A new average flow rate is calculated every other calendar year for each reporting sub-basin category starting the first calendar year of data collection. For a new producing sub-basin category, an average flow rate is calculated beginning in the first year of production.

(ii) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(2) *Calculation Methodology 2.* Calculate the total emissions for well venting for liquids unloading using Equation W–8 of this section.

$$E_{s,n} = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times CD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p \times \left(HR_{p,q} - 1.0\right)\times Z_{p,q}\right)\right] \qquad \text{(Eq. W-8)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.

W = Total number of wells with well venting for liquids unloading for each sub-basin.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

CD_p = Casing internal diameter for each well, p, in inches.

WD_p = Well depth from either the top of the well or the lowest packer to the bottom of the well, for each well, p, in feet.

SP_p = For each well, p, shut-in pressure or surface pressure for wells with tubing production or casing pressure for each well with no packers in pounds per square inch absolute (psia); or casing-to-tubing pressure ratio of one well with no packer from the same sub-basin multiplied by the tubing pressure of each well, p, in the sub-basin, in pounds per square inch absolute (psia).

V_p = Number of unloading events per year per well, p.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading event, q.

1.0 = Hours for average well to blowdown casing volume at shut-in pressure.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 1.0 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 1.0 then $Z_{p,q}$ is equal to 1.

(3) *Calculation Methodology 3.* Calculate emissions from well venting to the atmosphere for liquids unloading with plunger lift assist using Equation W–9 of this section.

$$E_{s,n} = \sum_{p=1}^{W}\left[V_p \times \left(\left(0.37\times10^{-3}\right)\times TD_p^2 \times WD_p \times SP_p\right) + \sum_{q=1}^{V_p}\left(SFR_p \times \left(HR_{p,q} - 0.5\right)\times Z_{p,q}\right)\right] \qquad \text{(Eq. W-9)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions at standard conditions, in cubic feet/year.

W = Total number of wells with plunger lift assist and well venting for liquids unloading for each sub-basin.

0.37×10^{-3} = {3.14 (pi)/4}/{14.7*144} (psia converted to pounds per square feet).

TD_p = Tubing internal diameter for each well, p, in inches.

WD_p = Tubing depth to plunger bumper for each well, p, in feet.

SP_p = Flow-line pressure for each well, p, in pounds per square inch absolute (psia), using engineering estimate based on best available data.

V_p = Number of unloading events per year for each well, p.

SFR_p = Average flow-line rate of gas for well, p, at standard conditions in cubic feet per hour. Use Equation W–33 to calculate the average flow-line rate at standard conditions.

$HR_{p,q}$ = Hours that each well, p, was left open to the atmosphere during each unloading event, q.

0.5 = Hours for average well to blowdown tubing volume at flow-line pressure.

$Z_{p,q}$ = If $HR_{p,q}$ is less than 0.5 then $Z_{p,q}$ is equal to 0. If $HR_{p,q}$ is greater than or equal to 0.5 then $Z_{p,q}$ is equal to 1.

(i)–(ii) [Reserved]

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(g) *Gas well venting during completions and workovers from hydraulic fracturing.* Calculate CH_4, CO_2 and N_2O annual emissions from gas well venting during completions involving hydraulic fracturing in wells and well workovers using Equation W–10A or Equation W–10B of this section. Equation W–10A applies to well venting when the backflow rate is measured or calculated, Equation W–10B applies when the backflow vent or flare volume is measured. Use Equation W–10A if the flow rate for backflow during well completions and workovers from hydraulic fracturing is known for the specified number of wells per paragraph (g)(1) in a sub-basin and well type (horizontal or vertical) combination. Use Equation W–10B if the flow volume for backflow during well completions and workovers from hydraulic fracturing is known for all wells in a sub-basin and well type (horizontal or vertical) combination. Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total gas emissions using calculations in paragraphs (u) and (v) of this section.

$$E_{s,n} = \sum_{p=1}^{W} \left[T_p \times FRM_s \times PR_{s,p} - EnF_{s,p} - SG_{s,p} \right] \qquad \text{(Eq. W-10A)}$$

$$E_{s,n} = \sum_{p=1}^{W} \left[FV_{s,p} - EnF_{s,p} \right] \qquad \text{(Eq. W-10B)}$$

Where:

$E_{s,n}$ = Annual volumetric total gas emissions in cubic feet at standard conditions from gas well venting during completions or workovers following hydraulic fracturing for each sub-basin and well type (horizontal vs. vertical) combination.

W = Total number of wells completed or worked over using hydraulic fracturing in a sub-basin and well type (horizontal vs. vertical) combination.

T_p = Cumulative amount of time of backflow for the completion or workover, in hours, for each well, p, in a sub-basin and well type (horizontal vs. vertical) combination during the reporting year.

FRM_s = Ratio of flowback during well completions and workovers from hydraulic fracturing to 30-day production rate from Equation W–12.

$PR_{s,p}$ = First 30-day average production flow rate in standard cubic feet per hour of each well p, as required in paragraph (g)(1) of this section.

$EnF_{s,p}$ = Volume of CO_2 or N_2 injected gas in cubic feet at standard conditions that was injected into the reservoir during an energized fracture job for each well p. If the fracture process did not inject gas into the reservoir, then $EnF_{s,p}$ is 0. If injected gas is CO_2 then $EnF_{s,p}$ is 0.

$SG_{s,p}$ = Volume of natural gas in cubic feet at standard conditions that was recovered into a flow-line for well p as per paragraph (g)(3) of this section. This parameter includes any natural gas that is injected into the well for clean-up. If no gas was recovered, $SG_{s,p}$ is 0.

$FV_{s,p}$ = Flow volume of each well (p) in standard cubic feet measured using a recording flow meter (digital or analog) on the vent line to measure flowback during the completion or workover according to methods set forth in § 98.234(b).

(1) The average flow rate for flowback during well completions and workovers from hydraulic fracturing shall be determined using measurement(s) for Calculation Methodology 1 or calculation(s) for Calculation Methodology 2 described in this paragraph (g)(1) of this section. If Equation W–10A is used, the number of measurements or calculations shall be determined per sub-basin and well type (horizontal or vertical) as follows: at least one measurement or calculation for less than or

equal to 25 completions or workovers; at least two measurements or calculations for 26 to 50 completions or workovers; at least three measurements or calculations for 51 to 100 completions or workovers; at least four measurements or calculations for 101 to 250 completions or workovers; and at least five measurements or calculations for greater than 250 completions or workovers.

(i) *Calculation Methodology 1.* When using Equation W–10A, for each measured well completion(s) in each gas producing sub-basin category and well type (horizontal or vertical) combination and for each measured well workover(s) in each gas producing sub-basin category and well type (horizontal or vertical) combination, a recording flow meter (digital or analog) shall be installed on the vent line, ahead of a flare or vent if used, to measure the backflow rate according to methods set forth in § 98.234(b).

(ii) *Calculation Methodology 2.* When using Equation W–10A, for each calculated horizontal well completion and each calculated vertical well completion in each gas producing sub-basin category and for each calculated well horizontal workover and for each calculated vertical well workover in each gas producing sub-basin category, record the well flowing pressure upstream (and downstream in subsonic flow) of a well choke according to methods set forth in § 98.234(b) to calculate the well backflow during well completions and workovers from hydraulic fracturing. Calculate emissions using Equation W–11A of this section for subsonic flow or Equation W–11B of this section for sonic flow. Use best engineering estimate based on best available data along with Equation W–11C of this section to determine whether the predominant flow is sonic or subsonic. If the value of R in Equation W–11C is greater than or equal to 2, then flow is sonic; otherwise, flow is subsonic:

$$FR_a = 1.27*10^5 * A * \sqrt{3430 * T_u * \left[\left(\frac{P_2}{P_1}\right)^{1.515} - \left(\frac{P_2}{P_1}\right)^{1.758}\right]} \qquad \text{(Eq. W-11A)}$$

Where:

FR_a = Average flow rate in cubic feet per hour, under actual subsonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

P_1 = Upstream pressure (psia).

T_u = Upstream temperature (degrees Kelvin).

P_2 = Downstream pressure (psia).

3430 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$FR_a = 1.27*10^5 * A * \sqrt{187.08 * T_u} \qquad \text{(Eq. W-11B)}$$

Where:

FR_a = Average flow rate in cubic feet per hour, under actual sonic flow conditions.

A = Cross sectional open area of the restriction orifice (m^2).

T_u = Upstream temperature (degrees Kelvin).

187.08 = Constant with units of $m^2/(sec^2 * K)$.

$1.27*10^5$ = Conversion from m^3/second to ft^3/hour.

$$R = {}^{P1}\!/_{P2} \qquad \text{(Eq. W-11C)}$$

Where:

R = Pressure ratio

P1 = Pressure upstream of the restriction orifice in pounds per square inch absolute.

P2 = Pressure downstream of the restriction orifice in pounds per square inch absolute.

(iii) For Equation W–10A, the ratio of backflow rate during well completions and workovers from hydraulic fracturing to 30-day production rate is calculated using Equation W–12 of this section.

$$FRM_s = \frac{\sum_{p=1}^{N} FR_{s,p}}{\sum_{p=1}^{N} PR_{s,p}} \qquad \text{(Eq. W-12)}$$

Where:

FRM_s = Ratio of flowback rate during well completions and workovers from hydraulic fracturing to 30-day production rate.

$FR_{s,p}$ = Measured flowback rate from Calculation Methodology 1 described in paragraph (g)(1)(i) of this section or calculated flow rate from Calculation Methodology 2 described in paragraph (g)(1)(ii) of this section in standard cubic feet per hour for well(s) p for each sub-basin and well type (horizontal or vertical) combination. Measured and calculated FR_a values shall be converted from actual conditions (FR_a) to standard conditions ($FR_{s,p}$) for each well p using Equation W–33 in paragraph (t) of this section. You may not use flow volume as used in Equation W–10B converted to a flow rate for this parameter.

$PR_{s,p}$ = First 30-day production rate in standard cubic feet per hour for each well p that was measured in the sub-basin and well type combination.

N = Number of measured or calculated well completions or workovers using hydraulic fracturing in a sub-basin and well type combination.

(iv) For Equation W–10A, the ratio of backflow rate during well completions and workovers from hydraulic fracturing to 30-day production rate for horizontal and vertical wells are applied to all horizontal and vertical well completions in the gas producing sub-basin and well type combination and to all horizontal and vertical well workovers, respectively, in the gas producing sub-basin and well type combination for the total number of hours of backflow for each of these wells.

(v) For Equation W–10A, new flow rates for horizontal and vertical gas well completions and horizontal and vertical gas well workovers in each sub-basin category shall be calculated once every two years starting in the first calendar year of data collection.

(2) The volume of CO_2 or N_2 injected into the well reservoir during energized hydraulic fractures will be measured using an appropriate meter as described in 98.234(b) or using receipts of gas purchases that are used for the energized fracture job.

(i) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(ii) [Reserved]

(3) Determine if the backflow gas from the well completion or workover from hydraulic fracturing is recovered with purpose designed equipment that separates natural gas from the backflow, and sends this natural gas to a flow-line (*e.g.*, reduced emissions completion or workovers).

(i) Use the factor $SG_{s,P}$ in Equation W–10A of this section, to adjust the emissions estimated in paragraphs (g)(1) through (g)(4) of this section by the magnitude of emissions captured using purpose designed equipment that separates saleable gas from the flowback as determined by engineering estimate based on best available data.

(ii) [Reserved]

(iii) Calculate gas volume at standard conditions using calculations in paragraph (t) of this section.

(4) Both CH_4 and CO_2 volumetric and mass emissions shall be calculated from volumetric total emissions using calculations in paragraphs (u) and (v) of this section.

(5) Calculate annual emissions from gas well venting during well completions and workovers from hydraulic fracturing to flares as follows:

(i) Use the total gas well venting volume during well completions and workovers as determined in paragraph (g) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers using hydraulic fracturing emissions from the flare. This adjustment to emissions from completions using flaring versus completions without flaring accounts for the conversion of CH_4 to CO_2 in the flare.

(h) *Gas well venting during completions and workovers without hydraulic fracturing.* Calculate CH_4, CO_2 and N_2O emissions from each gas well venting during well completions and workovers not involving hydraulic fracturing using Equation W–13 of this section:

$$E_{s,n} = N_{wo} * EF_{wo} + \sum_{p=1}^{f} V_p * T_p \qquad \text{(Eq. W-13)}$$

Where:

$E_{s,n}$ = Annual natural gas emissions in standard cubic feet from gas well venting during well completions and workovers without hydraulic fracturing.

N_{wo} = Number of workovers per sub-basin category that flare gas or vent gas to the atmosphere and do not involve hydraulic fracturing in the reporting year.

EF_{wo} = Emission Factor for non-hydraulic fracture well workover venting in standard cubic feet per workover. EF_{wo} = 3114 standard cubic feet natural gas per well workover without hydraulic fracturing.

p = Well completions 1 through f in a sub-basin.

f = Total number of well completions without hydraulic fracturing in a sub-basin category.

V_p = Average daily gas production rate in standard cubic feet per hour for each well completion without hydraulic fracturing, p. This is the total annual gas production volume divided by total number of hours the wells produced to the flow-line. For completed wells that have not established a production rate, you may use the average flow rate from the first 30 days of production. In the event that the well is completed less than 30 days from the end of the calendar year, the first 30 days of the production straddling the current and following calendar years shall be used.

T_p = Time each well completion without hydraulic fracturing, p, was venting in hours during the year.

(1) Volumetric emissions for both CH_4 and CO_2 shall be calculated from volumetric natural gas emissions using calculations in paragraph (u) of this section. Mass emissions for both CH_4 and CO_2 shall be calculated from volumetric natural gas emissions using calculations in paragraphs (v) of this section.

(2) Calculate annual emissions from gas well venting during well completions and workovers not involving hydraulic fracturing to flares as follows:

(i) Use the gas well venting volume during well completions and workovers as determined in paragraph (h) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine gas well venting during well completions and workovers emissions without hydraulic fracturing from the flare.

(i) *Blowdown vent stacks.* Calculate CO_2 and CH_4 blowdown vent stack emissions from depressurizing equipment(s) to reduce system pressure for planned or emergency shutdowns resulting from human intervention or to take equipment out of service for maintenance (excluding depressurizing to a flare, over-pressure relief, operating pressure control venting and blowdown of non-GHG gases; desiccant dehydrator blowdown venting before reloading is covered in paragraph (e)(5) of this section) as follows:

(1) Calculate the unique physical volume (including pipelines, compressor case or cylinders, manifolds, suction bottles, discharge bottles, and vessels) between isolation valves determined by

engineering estimates based on best available data.

(2) If the unique physical volume between isolation valves is greater than or equal to 50 cubic feet, retain logs of the number of blowdowns for each unique physical volume (including but not limited to compressors, vessels, pipelines, headers, fractionators, and tanks). Unique physical volumes smaller than 50 cubic feet are exempt from reporting under paragraph (i) of this section.

(3) Calculate the total annual venting emissions for unique volumes using either Equation W–14A or W–14B of this section.

$$E_{s,n} = N * \left(V \left(\frac{(459.67 + T_s)P_a}{(459.67 + T_a)P_s} \right) - V * C \right) \quad \text{(Eq. W-14A)}$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

N = Number of occurrences of blowdowns for each unique physical volume in calendar year.

V = Unique physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet.

C = Purge factor that is 1 if the unique physical volume is not purged or zero if the unique physical volume is purged using non-GHG gases.

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual conditions in the unique physical volume (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions in the unique physical volume (psia).

$$E_{s,n} = \sum_{p=1}^{N} \left[V \left(\frac{(459.67 + T_s)(P_{a,b,p} - P_{a,e,p})}{(459.67 + T_{a,p})P_s} \right) \right] \quad \text{(Eq. W-14B)}$$

Where:

$E_{s,n}$ = Annual natural gas venting emissions at standard conditions from blowdowns in cubic feet.

p = Individual occurrence of blowdown for the same unique physical volume.

N = Number of occurrences of blowdowns for each unique physical volume in the calendar year.

V = Total physical volume (including pipelines, compressors and vessels) between isolation valves in cubic feet for each blowdown ‘‘p.’’

T_s = Temperature at standard conditions (60 °F).

$T_{a,p}$ = Temperature at actual conditions in the unique physical volume (°F) for each blowdown ‘‘p’’.

P_s = Absolute pressure at standard conditions (14.7 psia).

$P_{a,b,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the beginning of the blowdown ‘‘p’’.

$P_{a,e,p}$ = Absolute pressure at actual conditions in the unique physical volume (psia) at the end of the blowdown ‘‘p’’; 0 if blowdown volume is purged using non-GHG gases.

(4) Calculate both CH_4 and CO_2 volumetric and mass emissions using calculations in paragraph (u) and (v) of this section.

(j) *Onshore production storage tanks.* Calculate CH_4, CO_2 and N_2O (when flared) emissions from atmospheric pressure fixed roof storage tanks receiving hydrocarbon produced liquids from onshore petroleum and natural gas production facilities (including stationary liquid storage not owned or operated by the reporter), calculate annual CH_4 and CO_2 emissions using any of the calculation methodologies described in this paragraph (j).

(1) *Calculation Methodology 1.* For separators with annual average daily throughput of oil greater than or equal to 10 barrels per day. Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks using operating conditions in the last wellhead gas-liquid separator before liquid transfer to storage tanks. Calculate flashing emissions with a software program, such as AspenTech HYSYS® or API 4697 E&P Tank, that uses the Peng-Robinson equation of state, models flashing emissions, and speciates CH_4 and CO_2 emissions that will result when the oil from the separator enters an atmospheric pressure storage tank. A minimum of the following parameters determined for typical operating conditions over the year by engineering estimate and process knowledge based on best available data must be used to characterize emissions from liquid transferred to tanks.

(i) Separator temperature.

(ii) Separator pressure.

(iii) Sales oil or stabilized oil API gravity.

(iv) Sales oil or stabilized oil production rate.

(v) Ambient air temperature.

(vi) Ambient air pressure.

(vii) Separator oil composition and Reid vapor pressure. If this data is not available, determine these parameters by selecting one of the methods described under paragraph (j)(1) (vii) of this section.

(A) If separator oil composition and Reid vapor pressure default data are provided with the software program, select the default values that most closely match your separator pressure first, and API gravity secondarily.

(B) If separator oil composition and Reid vapor pressure data are available through your previous analysis, select the latest available analysis that is representative of produced crude oil or condensate from the sub-basin category.

(C) Analyze a representative sample of separator oil in each sub-basin category for oil composition and Reid vapor pressure using an appropriate standard method published by a consensus-based standards organization.

(2) *Calculation Methodology 2.* Calculate annual CH_4 and CO_2 emissions from onshore production storage tanks for wellhead gas-liquid separators with annual average daily throughput of oil greater than or equal to 10 barrels per day by assuming that all of the CH_4 and CO_2 in solution at separator temperature and pressure is emitted from oil sent to storage tanks. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice as described in § 98.234(b) to sample and analyze separator oil composition at separator pressure and temperature.

(3) *Calculation Methodology 3.* For wells with annual average daily oil production greater than or equal to 10 barrels per day that flow directly to atmospheric storage tanks without passing through a wellhead separator, calculate annual CH_4 and CO_2 emissions by either of the methods in paragraph (j)(3) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of produced oil and gas from the sub-basin category and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(ii) If well production oil and gas compositions are not available, use default oil and gas compositions in software programs, such as API 4697 E&P Tank, that most closely match your well production gas/oil ratio and API gravity and assume all of the CH_4 and CO_2 in both oil and gas are emitted from the tank.

(4) *Calculation Methodology 4.* For wells with annual average daily oil production greater than or equal to 10 barrels per day that flow to a separator not at the well pad, calculate annual CH_4 and CO_2 emissions by either of the methods in paragraph (j)(4) of this section:

(i) If well production oil and gas compositions are available through your previous analysis, select the latest available analysis that is representative of oil at separator pressure determined by best available data and assume all of the CH_4 and CO_2 in the oil is emitted from the tank.

(ii) If well production oil composition is not available, use default oil composition in software programs, such as API 4697 E&P Tank, that most closely match your well production API gravity and pressure in the off-well pad separator determined by best available data. Assume all of the CH_4 and CO_2 in the oil phase is emitted from the tank.

(5) *Calculation Methodology 5.* For well pad gas-liquid separators and for wells flowing off a well pad without passing through a gas-liquid separator with annual average daily throughput of oil less than 10 barrels per day use Equation W–15 of this section:

$$E_{s,i} = EF_i * Count * 1000 \qquad \text{(Eq. W-15)}$$

where:

$E_{s,i}$ = Annual total volumetric GHG emissions (either CO_2 or CH_4) at standard conditions in cubic feet.

EF_i = Population emission factor for separators or wells in thousand standard cubic feet per separator or well per year, for crude oil use 4.2 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia, and for gas condensate use 17.6 for CH_4 and 2.8 for CO_2 at 60 °F and 14.7 psia.

Count = Total number of separators or wells with annual average daily throughput less than 10 barrels per day. Count only separators or wells that feed oil directly to the storage tank.

1,000 = Conversion from thousand standard cubic feet to standard cubic feet.

(6) Determine if the storage tank receiving your separator oil has a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (j)(1) through (j)(5) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(7) Determine if the storage tank receiving your separator oil is sent to flare(s).

(i) Use your separator flash gas volume and gas composition as determined in this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine your contribution to storage tank emissions from the flare.

(8) Calculate emissions from occurrences of well pad gas-liquid separator liquid dump valves not closing during the calendar year by using Equation W–16 of this section.

$$E_{s,i} = \left(CF_n * \frac{E_n}{8760} * T_n\right) + \left(\frac{E_n}{8760} * \left(8760 - T_n\right)\right) \qquad \text{(Eq. W-16)}$$

where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each storage tank in cubic feet.

E_n = Storage tank emissions as determined in Calculation Methodologies 1, 2, or 4 in paragraphs (j)(1), (j)(2) and (j)(4) of this section (with wellhead separators) in standard cubic feet per year.

T_n = Total time the dump valve is not closing properly in the calendar year in hours. T_n is estimated by maintenance or operations records (records) such that when a record shows the valve to be open improperly, it is assumed the valve was open for the entire time period preceding the record starting at either the beginning of the calendar year or the previous record showing it closed properly within the calendar year. If a subsequent record shows it is closing properly, then assume from that time forward the valve closed properly until either the next record of it not closing properly or, if there is no subsequent record, the end of the calendar year.

CF_n = Correction factor for tank emissions for time period T_n is 3.87 for crude oil production. Correction factor for tank emissions for time period T_n is 5.37 for gas condensate production. Correction factor for tank emissions for time period T_n is 1.0 for periods when the dump valve is closed.

8,760 = Conversion to hourly emissions.

(9) Calculate both CH_4 and CO_2 mass emissions from volumetric natural gas emissions using calculations in paragraph (v) of this section.

(k) *Transmission storage tanks.* For vent stacks connected to one or more transmission condensate storage tanks, either water or hydrocarbon, without vapor recovery, in onshore natural gas transmission compression, calculate CH_4, CO_2 and N_2O annual emissions from compressor scrubber dump valve leakage as follows:

(1) Monitor the tank vapor vent stack annually for emissions using an optical gas imaging instrument according to methods set forth in § 98.234(a)(1) or by directly measuring the tank vent using a flow meter or high volume sampler according to methods in § 98.234(b) through (d) for a duration of 5 minutes, or a calibrated bag according to methods in § 98.234(b). Or you may annually monitor leakage through compressor scrubber dump valve(s) into the tank using an acoustic leak detection device according to methods set forth in § 98.234(a)(5).

(2) If the tank vapors from the vent stack are continuous for 5 minutes, or the acoustic leak detection device detects a leak, then use one of the following two methods in paragraph (k)(2) of this section to quantify annual emissions:

(i) Use a meter, such as a turbine meter, calibrated bag, or high flow sampler to estimate tank vapor volumes from the vent stack according to methods set forth in § 98.234(b) through (d). If you do not have a continuous flow measurement device, you may install a flow measuring device on the tank vapor vent stack. If the vent is directly measured for five minutes under paragraph § 98.233(k)(1) of this section to detect continuous leakage, this serves as the measurement.

(ii) Use an acoustic leak detection device on each scrubber dump valve connected to the tank according to the method set forth in § 98.234(a)(5).

(iii) Use the appropriate gas composition in paragraph (u)(2)(iii) of this section.

(iv) Calculate GHG volumetric and mass emissions at standard conditions using calculations in paragraphs (t), (u), and (v) of this section, as applicable to the monitoring equipment used.

(3) If the leaking dump valve(s) is fixed following leak detection, the annual emissions shall be calculated from the beginning of the calendar year to the time the valve(s) is repaired.

(4) Calculate annual emissions from storage tanks to flares as follows:

(i) Use the storage tank emissions volume and gas composition as determined in paragraphs (k)(1) through (k)(3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine storage tank emissions sent to a flare.

(l) *Well testing venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) well testing venting and flaring emissions as follows:

(1) Determine the gas to oil ratio (GOR) of the hydrocarbon production from oil well(s) tested. Determine the production rate from gas well(s) tested.

(2) If GOR cannot be determined from your available data, then you must measure quantities reported in this section according to one of the two procedures in paragraph (l)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W–17A or Equation W–17B of this section.

$$E_{a,n} = GOR * FR * D \qquad \text{(Eq. W-17A)}$$

$$E_{a,n} = PR * D \qquad \text{(Eq. W-17B)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions from well(s) testing in cubic feet under actual conditions.

GOR = Gas to oil ratio in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

FR = Flow rate in barrels of oil per day for the oil well(s) being tested.

PR = Average annual production rate in actual cubic feet per day for the gas well(s) being tested.

D = Number of days during the year, the well(s) is tested.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from well testing to flares as follows:

(i) Use the well testing emissions volume and gas composition as determined in paragraphs (l)(1) through (3) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine well testing emissions from the flare.

(m) *Associated gas venting and flaring.* Calculate CH_4, CO_2 and N_2O (when flared) associated gas venting and flaring emissions not in conjunction with well testing (refer to paragraph (l): Well testing venting and flaring of this section) as follows:

(1) Determine the GOR of the hydrocarbon production from each well whose associated natural gas is vented or flared. If GOR from each well is not available, the GOR from a cluster of wells in the same sub-basin category shall be used.

(2) If GOR cannot be determined from your available data, then use one of the two procedures in paragraph (m)(2) of this section to determine GOR:

(i) You may use an appropriate standard method published by a consensus-based standards organization if such a method exists.

(ii) Or you may use an industry standard practice as described in § 98.234(b).

(3) Estimate venting emissions using Equation W–18 of this section.

$$E_{a,n} = \sum_{q=1}^{y}\sum_{p=1}^{x} GOR_{p,q} * V_{p,q} \qquad \text{(Eq. W-18)}$$

Where:

$E_{a,n}$ = Annual volumetric natural gas emissions, at the facility level, from associated gas venting under actual conditions, in cubic feet.

$GOR_{p,q}$ = Gas to oil ratio, for well p in sub-basin q, in cubic feet of gas per barrel of oil; oil here refers to hydrocarbon liquids produced of all API gravities.

$V_{p,q}$ = Volume of oil produced, for well p in sub-basin q, in barrels in the calendar year during which associated gas was vented or flared.

x = Total number of wells in sub-basin that vent or flare associated gas.

y = Total number of sub-basins in a basin that contain wells that vent or flare associated gas.

(4) Calculate natural gas volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(5) Calculate both CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using calculations in paragraphs (u) and (v) of this section.

(6) Calculate emissions from associated natural gas to flares as follows:

(i) Use the associated natural gas volume and gas composition as determined in paragraph (m)(1) through (4) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine associated gas emissions from the flare.

(n) *Flare stack emissions.* Calculate CO_2, CH_4, and N_2O emissions from a flare stack as follows:

(1) If you have a continuous flow measurement device on the flare, you must use the measured flow volumes to calculate the flare gas emissions. If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can install a flow measuring device on the flare or use engineering calculations based on process knowledge, company records, and best available data.

(2) If you have a continuous gas composition analyzer on gas to the flare, you must use these compositions in calculating emissions. If you do not have a continuous gas composition analyzer on gas to the flare, you must use the appropriate gas compositions for each stream of hydrocarbons going to the flare as follows:

(i) For onshore natural gas production, determine natural gas composition using (u)(2)(i) of this section.

(ii) For onshore natural gas processing, when the stream going to flare is natural gas, use the GHG mole percent in feed natural gas for all streams upstream of the de-methanizer or dew point control, and GHG mole percent in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the de-methanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams.

(iii) For any applicable industry segment, when the stream going to the flare is a hydrocarbon product stream, such as methane, ethane, propane, butane, pentane-plus and mixed light hydrocarbons, then you may use a representative composition from the source for the stream determined by engineering calculation based on process knowledge and best available data.

(3) Determine flare combustion efficiency from manufacturer. If not available, assume that flare combustion efficiency is 98 percent.

(4) Calculate GHG volumetric emissions at actual conditions using Equations W–19, W–20, and W–21 of this section.

$$E_{a,CH4}(un-combusted) = V_a * (1-\eta) * X_{CH4} \quad \text{(Eq. W-19)}$$

$$E_{a,CO2}(un-combusted) = V_a * X_{CO2} \quad \text{(Eq. W-20)}$$

$$E_{a,CO2}(combusted) = \sum_{J=1}^{5} \left(\eta * V_a * Y_j * R_j\right) \quad \text{(Eq. W-21)}$$

where:

E_{a,CH_4}(un-combusted) = Contribution of annual un-combusted CH_4 emissions from flare stack in cubic feet, under actual conditions.

E_{a,CO_2}(un-combusted) = Contribution of annual un-combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.
E_{a,CO_2}(combusted) = Contribution of annual combusted CO_2 emissions from flare stack in cubic feet, under actual conditions.
V_a = Volume of gas sent to flare in cubic feet, during the year.
η = Fraction of gas combusted by a burning flare (default is 0.98). For gas sent to an unlit flare, η is zero.
X_{CH_4} = Mole fraction of CH_4 in gas to the flare.
X_{CO_2} = Mole fraction of CO_2 in gas to the flare.
Y_j = Mole fraction of gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes-plus).
R_j = Number of carbon atoms in the gas hydrocarbon constituent j: 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes-plus).

(5) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(6) Calculate both CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(7) [Reserved]

(8) Calculate N_2O emissions from flare stacks using Equation W–40 in paragraph (z) of this section.

(9) If you operate and maintain a CEMS that has both a CO_2 concentration monitor and volumetric flow rate monitor, you must calculate only CO_2 emissions for the flare. You must follow the Tier 4 Calculation Methodology and all associated calculation, quality assurance, reporting, and recordkeeping requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources). If a CEMS is used to calculate flare stack emissions, the requirements specified in paragraphs (n)(1) through (n)(7) are not required. If a CO_2 concentration monitor and volumetric flow rate monitor are not available, you may elect to install a CO_2 concentration monitor and a volumetric flow rate monitor that comply with all of the requirements specified for the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion).

(10) The flare emissions determined under paragraph (n) of this section must be corrected for flare emissions calculated and reported under other paragraphs of this section to avoid double counting of these emissions.

(11) If source types in §98.233 use Equations W–19 through W–21 of this section, use estimate of emissions under actual conditions for the parameter, V_a, in these equations.

(o) *Centrifugal compressor venting*. Calculate CH_4, CO_2 and N_2O (when flared) emissions from both wet seal and dry seal centrifugal compressor vents as follows:

(1) For each centrifugal compressor covered by §98.232 (d)(2), (e)(2), (f)(2), (g)(2), and (h)(2) you must conduct an annual measurement in the operating mode in which it is found. Measure emissions from all vents (including emissions manifolded to common vents) including wet seal oil degassing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement.

(i) Operating mode, blowdown valve leakage through the blowdown vent, wet seal and dry seal compressors.

(ii) Operating mode, wet seal oil degassing vents.

(iii) Not operating, depressurized mode, unit isolation valve leakage through open blowdown vent, without blind flanges, wet seal and dry seal compressors.

(A) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(2) For wet seal oil degassing vents, determine vapor volumes sent to an atmospheric vent or flare, using a temporary meter such as a vane anemometer or permanent flow meter according to 98.234(b) of this section. If you do not have a permanent flow meter, you may install a permanent flow meter on the wet seal oil degassing tank vent.

(3) For blowdown valve leakage and unit isolation valve leakage to open ended vents, you can use one of the following methods: Calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively. For through valve leakage, such as isolation valves, you may use an acoustic leak detection device according to methods set forth in § 98.234(a). If you do not have a flow meter, you may install a port for insertion of a temporary meter, or a permanent flow meter, on the vents.

(4) Estimate annual emissions using the flow measurement and Equation W–22 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} * (1 - B_m) \qquad \text{(Eq. W-22)}$$

where:

$E_{s,i,m}$ = Annual GHG_i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG_i in the vent gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

B_m = Fraction of operating time that the vent gas is sent to vapor recovery or fuel gas as determined by keeping logs of the number of operating hours for the vapor recovery system and the time that vent gas is directed to the fuel gas system or sales.

(5) Calculate annual emissions from each centrifugal compressor using Equation W–23 of this section.

$$E_{s,i,m} = EF_m * T_m * GHG_i \qquad \text{(Eq. W-23)}$$

where:

$E_{s,i,m}$ = Annual total volumetric GHG emissions at standard conditions from each centrifugal compressor for mode-source combination m, in cubic feet.

EF_m = Reporter emission factor for each mode m, in cubic feet per hour, from Equation W–24 of this section as calculated in paragraph 6.

T_m = Total time in hours per year the compressor was in each mode, as listed in paragraph (o)(1)(i) through (o)(1)(iii).

GHG_i = For onshore natural gas processing facilities, concentration of GHG $_i$, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8),GHG_i equals 1.

(6) You shall use the flow measurements of operating mode wet seal oil degassing vent, operating mode blowdown valve vent and not operating depressurized mode isolation valve vent for all the reporter's compressor modes not measured in the calendar year to develop the following emission factors using Equation W–24 of this section for each emission source and mode as listed in paragraph (o)(1)(i) through (o)(1)(iii).

$$EF_m = \frac{\sum_{p=1}^{Count_m} MT_{m,p}}{Count_m} \qquad \text{(Eq. W-24)}$$

where:

EF_m = Reporter emission factors for compressor in the three modes m (as listed in paragraph (o)(1)(i) through (o)(1)(iii)) in cubic feet per hour.

$MT_{m,p}$ = Flow measurements from all centrifugal compressor sources in each mode-source combination, m, for each measured compressor, p, in standard cubic feet per hour.

$Count_m$ = Total number of compressors measured.

m = Compressor mode-source combination as listed in paragraphs (o)(1)(i) through (o)(1)(iii).

(i) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements in paragraph (o)(6) of this section.

(ii) [Reserved]

(7) Onshore petroleum and natural gas production shall calculate emissions from centrifugal compressor wet seal oil degassing vents as follows:

$$E_{s,i} = Count * EF_i \quad \text{(Eq. W-25)}$$

where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from centrifugal compressor wet seals in cubic feet.

Count = Total number of centrifugal compressors for the reporter.

EF_i = Emission factor for GHG_i. Use 1.2×10^7 standard cubic feet per year per compressor for CH_4 and 5.30×10^5 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

(8) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(9) Calculate emissions from seal oil degassing vent vapors to flares as follows:

(i) Use the seal oil degassing vent vapor volume and gas composition as determined in paragraphs (o)(5) of this section.

(ii) Use the calculation methodology of flare stacks in paragraph (n) of this section to determine degassing vent vapor emissions from the flare.

(p) *Reciprocating compressor venting.* Calculate CH_4 and CO_2 emissions from all reciprocating compressor vents as follows. For each reciprocating compressor covered in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1) you must conduct an annual measurement for each compressor in the mode in which it is found during the annual measurement, except as specified in paragraph (p)(9) of this section. Measure emissions from (including emissions manifolded to common vents) reciprocating rod packing vents, unit isolation valve vents, and blowdown valve vents. Record emissions from the following vent types in the specified compressor modes during the annual measurement as follows:

(1) Operating or standby pressurized mode, blowdown vent leakage through the blowdown vent stack.

(2) Operating mode, reciprocating rod packing emissions.

(3) Not operating, depressurized mode, unit isolation valve leakage through the blowdown vent stack, without blind flanges.

(i) For the not operating, depressurized mode, each compressor must be measured at least once in any three consecutive calendar years if this mode is not found in the annual measurement. If a compressor is not operated and has blind flanges in place throughout the 3 year period, measurement is not required in this mode. If the compressor is in standby depressurized mode without blind flanges in place and is not operated throughout the 3 year period, it must be measured in the standby depressurized mode.

(ii) [Reserved]

(4) If reciprocating rod packing and blowdown vent are connected to an open-ended vent line use one of the following two methods to calculate emissions:

(i) Measure emissions from all vents (including emissions manifolded to common vents) including rod packing, unit isolation valves, and blowdown vents using either calibrated bagging or high volume sampler according to methods set forth in § 98.234(c) and § 98.234(d), respectively.

(ii) Use a temporary meter such as a vane anemometer or a permanent meter such as an orifice meter to measure emissions from all vents (including emissions manifolded to a common vent) including rod packing vents and unit isolation valve leakage through blowdown vents according to methods set forth in § 98.234(b). If you do not have a permanent flow meter, you may install a port for insertion of a temporary meter or a permanent flow meter on the vents. For through-valve leakage to open ended vents, such as unit isolation valves on not operating, depressurized compressors and blowdown valves on pressurized compressors, you may use an acoustic detection device according to methods set forth in § 98.234(a).

(5) If reciprocating rod packing is not equipped with a vent line use the following method to calculate emissions:

(i) You must use the methods described in § 98.234(a) to conduct annual leak detection of equipment leaks from the packing case into an open distance piece, or from the compressor crank case breather cap or other vent with a closed distance piece.

(ii) Measure emissions found in paragraph (p)(5)(i) of this section using an appropriate meter, or calibrated bag, or high volume sampler according to methods set forth in § 98.234(b), (c), and (d), respectively.

(6) Estimate annual emissions using the flow measurement and Equation W–26 of this section.

$$E_{s,i,m} = MT_m * T_m * M_{i,m} \quad \text{(Eq. W-26)}$$

where:

$E_{s,i,m}$ = Annual GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions, in cubic feet.

MT_m = Measured gas emissions in standard cubic feet per hour.

T_m = Total time the compressor is in the mode for which $E_{s,i,m}$ is being calculated, in the calendar year in hours.

$M_{i,m}$ = Mole fraction of GHG i in gas; use the appropriate gas compositions in paragraph (u)(2) of this section.

(7) Calculate annual emissions from each reciprocating compressor using Equation W–27 of this section.

$$E_{s,i,m} = EF_m * T_m * GHG_i \quad \text{(Eq. W-27)}$$

where:

$E_{s,i,m}$ = Annual total volumetric GHG emissions at standard conditions from each reciprocating compressor for mode-source combination m, in cubic feet.

EF_m = Reporter emission factor for each mode, m, in cubic feet per hour, from Equation W–28 of this section as calculated in paragraph (p)(7)(i) of this section.

T_m = Total time in hours per year the compressor was in each mode, m, as listed in paragraph (p)(1) through (p)(3).

GHG_i = For onshore natural gas processing facilities, concentration of GHG i, CH_4 or CO_2, in produced natural gas or feed natural gas; for other facilities listed in § 98.230(a)(4) through (a)(8), GHG_i equals 1.

m = Compressor mode as listed in paragraph (p)(1) through (p)(3).

(i) You shall use the flow meter readings from measurements of operating and standby pressurized blowdown vent, operating mode vents, not operating depressurized isolation valve vent for all the reporter's compressor modes not measured in the calendar year to develop the following emission factors using Equation W–28 of this section for each mode as listed in paragraph (p)(1) through (p)(3).

$$EF_m = \frac{\sum_{p=1}^{Count_m} MT_{m,p}}{Count_m} \quad \text{(Eq. W-28)}$$

where:

EF_m = Reporter emission factors for compressor in the three modes, m, in cubic feet per hour.

$MT_{m,p}$ = Flow measurements from all reciprocating compressor sources in each mode-source combination, m, for each measured compressor, p, in standard cubic feet per hour.

$Count_m$ = Total number of compressors measured in each mode, m.

m = Compressor mode-source combination as listed in (p)(1) through (p)(3).

(A) You must combine emissions for blowdown vents, measured in the operating and standby pressurized modes.

(B) The emission factors must be calculated annually. You must use all measurements from the current calendar year and the preceding two calendar years, totaling three consecutive calendar years of measurements.

(ii) [Reserved]

(8) Determine if the reciprocating compressor vent vapors are sent to a vapor recovery system.

(i) Adjust the emissions estimated in paragraphs (p)(7) of this section downward by the magnitude of emissions recovered using a vapor recovery system as determined by engineering estimate based on best available data.

(ii) [Reserved]

(9) Onshore petroleum and natural gas production shall calculate emissions from reciprocating compressors as follows:

$$E_{s,i} = Count * EF_i \quad \text{(Eq. W-29)}$$

where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from reciprocating compressors in cubic feet.

Count = Total number of reciprocating compressors for the reporter.

EF_i = Emission factor for GHG_i. Use 9.48×10^3 standard cubic feet per year per compressor for CH_4 and 5.27×10^2 standard cubic feet per year per compressor for CO_2 at 60 °F and 14.7 psia.

(10) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in paragraphs (u) and (v) of this section.

(q) *Leak detection and leaker emission factors.* You must use the methods described in § 98.234(a) to conduct leak detection(s) of equipment leaks from all component types listed in § 98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1). This paragraph (q) applies to component types in streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Component types in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of this paragraph (q) and do not need to be reported. If equipment leaks are detected for sources listed in this paragraph (q), calculate equipment leak emissions per component type per reporting facility using Equations W–30A or W–30B of this section for each component type. Use Equation W–30A for industry segments listed in 98.230(a)(3)–(a)(7). Use Equation W–30B for industry segments listed in 98.230(a)(8).

$$E_{s,i} = GHG_i * \sum_{p=1}^{x} \left(EF * T_p \right) \qquad \text{(Eq. W-30A)}$$

$$E_{s,i} = GHG_i * \sum_{q=t-n+1}^{t} \sum_{p=1}^{x} \left(EF * T_{p,q} \right) \qquad \text{(Eq. W-30B)}$$

Where:

$E_{s,i}$ = Annual total volumetric GHG emissions at standard conditions from each component type in cubic feet, as specified in (q)(1) through (q)(8) of this section.

x = Total number of each component type.

EF = Leaker emission factor for specific component types listed in Table W–2 through Table W–7 of this subpart.

GHG_i = For onshore natural gas processing facilities, concentration of GHG_i, CH_4 or CO_2, in the total hydrocarbon of the feed natural gas; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

T_p = The total time the component, p, was found leaking and operational, in hours. If one leak detection survey is conducted, assume the component was leaking for the entire calendar year. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey (if not found leaking in the previous survey) or the beginning of the calendar year (if it was found leaking in the previous survey). For the last leak detection survey in the calendar year, assume that all leaking components continue to leak until the end of the calendar year.

t = Calendar year of reporting.

n = The number of years over which one complete cycle of leak detection is conducted over all the T–D transfer stations in a natural gas distribution facility; $0 < n \leq 5$. For the first (n–1) calendar years of reporting the summation in Equation W–30B should be for years that the data is available.

$T_{p,q}$ = The total time the component, p, was found leaking and operational, in hours, in year q. If one leak detection survey is conducted, assume the component was leaking for the entire period n. If multiple leak detection surveys are conducted, assume that the component found to be leaking has been leaking since the previous survey (if not found to be leaking in the previous survey) or the beginning of the calendar year (if it was found to be leaking in the previous survey). For the last leak detection survey in the cycle, assume that all leaking components continue to leak until the end of the cycle.

(1) You must select to conduct either one leak detection survey in a calendar year or multiple complete leak detection surveys in a calendar year. The number of leak detection surveys selected must be conducted during the calendar year.

(2) Calculate GHG mass emissions in carbon dioxide equivalent at standard conditions using calculations in paragraph (v) of this section.

(3) Onshore natural gas processing facilities shall use the appropriate default leaker emission factors listed in Table W–2 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(4) Onshore natural gas transmission compression facilities shall use the appropriate default leaker emission factors listed in Table W–3 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(5) Underground natural gas storage facilities for storage stations shall use the appropriate default leaker emission factors listed in Table W–4 of this subpart for equipment leaks detected from valves, connectors, open ended lines, pressure relief valves, and meters.

(6) LNG storage facilities shall use the appropriate default leaker emission factors listed in Table W–5 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(7) LNG import and export facilities shall use the appropriate default leaker

emission factors listed in Table W–6 of this subpart for equipment leaks detected from valves, pump seals, connectors, and other.

(8) Natural gas distribution facilities for above grade transmission-distribution transfer stations, shall use the appropriate default leaker emission factors listed in Table W–7 of this subpart for equipment leaks detected from connectors, block valves, control valves, pressure relief valves, orifice meters, regulators, and open ended lines. Leak detection at natural gas distribution facilities is only required at above grade stations that qualify as transmission-distribution transfer stations. Below grade transmission-distribution transfer stations and all metering-regulating stations that do meet the definition of transmission-distribution transfer stations are not required to perform component leak detection under this section.

(i) Natural gas distribution facilities may choose to conduct leak detection at the T–D transfer stations over multiple years, not exceeding a five year period to cover all T–D transfer stations. If the facility chooses to use the multiple year option then the number of T–D transfer stations that are monitored in each year should be approximately equal across all years in the cycle without monitoring the same station twice during the multiple year survey.

(ii) [Reserved]

(r) *Population count and emission factors.* This paragraph applies to emissions sources listed in § 98.232 (c)(21), (f)(5), (g)(3), (h)(4), (i)(2), (i)(3), (i)(4), (i)(5), and (i)(6) on streams with gas content greater than 10 percent CH_4 plus CO_2 by weight. Emissions sources in streams with gas content less than 10 percent CH_4 plus CO_2 by weight do not need to be reported. Tubing systems equal to or less than one half inch diameter are exempt from the requirements of paragraph (r) of this section and do not need to be reported. Calculate emissions from all sources listed in this paragraph using Equation W–31 of this section.

$$E_{s,i} = Count_s * EF_s * GHG_i * T_s \qquad \text{(Eq. W-31)}$$

Where:

$E_{s,i}$ = Annual volumetric GHG emissions at standard conditions from each component type in cubic feet.

$Count_s$ = Total number of this type of emission source at the facility. For onshore petroleum and natural gas production, average component counts are provided by major equipment piece in Tables W–1B and Table W–1C of this subpart. Use average component counts as appropriate for operations in Eastern and Western U.S., according to Table W–1D of this subpart. Underground natural gas storage shall count the components listed for population emission factors in Table W–4. LNG Storage shall count the number of vapor recovery compressors. LNG import and export shall count the number of vapor recovery compressors. Natural gas distribution shall count the meter/regulator runs as described in paragraph (r)(6) of this section.

EF = Population emission factor for the specific component type, as listed in Table W–1A and Tables W–3 through Table W–7 of this subpart. Use appropriate population emission factor for operations in Eastern and Western U.S., according to Table W–1D of this subpart. EF for meter/regulator runs at above grade metering-regulating stations is determined in Equation W–32 of this section.

GHG_i = For onshore petroleum and natural gas production facilities, concentration of GHG_i, CH_4 or CO_2, in produced natural gas as defined in paragraph (u)(2) of this section; for onshore natural gas transmission compression and underground natural gas storage, GHG_i equals 0.975 for CH_4 and 1.1×10^{-2} for CO_2; for LNG storage and LNG import and export equipment, GHG_i equals 1 for CH_4 and 0 for CO_2; and for natural gas distribution, GHG_i equals 1 for CH_4 and 1.1×10^{-2} CO_2.

T_s = Average estimated time that each component type associated with the equipment leak emission was operational in the calendar year, in hours, using engineering estimate based on best available data.

(1) Calculate both CH_4 and CO_2 mass emissions from volumetric emissions using calculations in paragraph (v) of this section.

(2) Onshore petroleum and natural gas production facilities shall use the appropriate default population emission factors listed in Table W–1A of this subpart for equipment leaks from valves, connectors, open ended lines, pressure relief valves, pump, flanges, and other. Major equipment and components associated with gas wells are considered gas service components in reference to Table W–1A of this subpart and major natural gas equipment in reference to Table W–1B of this subpart. Major equipment and components associated with crude oil wells are considered crude service components in reference to Table W–1A of this subpart and major crude oil equipment in reference to Table W–1C of this subpart. Where facilities conduct EOR operations the emissions factor listed in Table W–1A of this subpart shall be used to estimate all streams of gases, including recycle CO_2 stream. The component count can be determined using either of the methodologies described in this paragraph (r)(2). The same methodology must be used for the entire calendar year.

(i) *Component Count Methodology 1.* For all onshore petroleum and natural gas production operations in the facility perform the following activities:

(A) Count all major equipment listed in Table W–1B and Table W–1C of this subpart. For meters/piping, use one meters/piping per well-pad.

(B) Multiply major equipment counts by the average component counts listed in Table W–1B and W–1C of this subpart for onshore natural gas production and onshore oil production, respectively. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(ii) *Component Count Methodology 2.* Count each component individually for the facility. Use the appropriate factor in Table W–1A of this subpart for operations in Eastern and Western U.S. according to the mapping in Table W–1D of this subpart.

(3) Underground natural gas storage facilities for storage wellheads shall use the appropriate default population emission factors listed in Table W–4 of this subpart for equipment leak from connectors, valves, pressure relief valves, and open ended lines.

(4) LNG storage facilities shall use the appropriate default population emission factors listed in Table W–5 of this subpart for equipment leak from vapor recovery compressors.

(5) LNG import and export facilities shall use the appropriate default population emission factor listed in Table W–6 of this subpart for equipment leak from vapor recovery compressors.

(6) Natural gas distribution facilities shall use the appropriate emission factors as described in paragraph (r)(6) of this section.

(i) Below grade metering-regulating stations; distribution mains; and distribution services, shall use the appropriate default population emission factors listed in Table W–7 of this subpart. Below grade T–D transfer stations shall use the emission factor for below grade metering-regulating stations.

(ii) Emissions from all above grade metering-regulating stations (including above grade TD transfer stations) shall be calculated by applying the emission factor calculated in Equation W–32 and the total count of meter/regulator runs at all above grade metering-regulating stations (inclusive of TD transfer stations) to Equation W–31. The facility wide emission factor in Equation W–32 will be calculated by using the total volumetric GHG emissions at standard conditions for all equipment leak sources calculated in Equation W–30B in paragraph (q)(8) of this section and the count of meter/regulator runs located at above grade transmission-distribution transfer stations that were monitored over the years that constitute one complete cycle as per paragraph (q)(8)(i) of this section. A meter on a regulator run is considered one meter/regulator run. Reporters that do not have above grade T–D transfer stations shall report a count of above grade metering-regulating stations only and do not have to comply with § 98.236(c)(16)(xix).

$$EF = \frac{E_{s,i} \div 8760}{Count} \qquad \text{(Eq. W-32)}$$

Where:

EF = Facility emission factor for a meter/regulator run per component type at above grade metering-regulating for GHG_i in cubic feet per meter/regulator run per hour.

$E_{s,i}$ = Annual volumetric GHG i emissions, CO_2 or CH_4 at standard condition from each component type at all above grade TD transfer stations, from Equation W–30B.

Count = Total number of meter/regulator runs at all TD transfer stations that were monitored over the years that constitute one complete cycle as per (q)(8)(i) of this section.

8760 = Conversion to hourly emissions

(s) *Offshore petroleum and natural gas production facilities.* Report CO_2, CH_4, and N_2O emissions for offshore petroleum and natural gas production from all equipment leaks, vented emission, and flare emission source types as identified in the data collection and emissions estimation study conducted by BOEMRE in compliance with 30 CFR 250.302 through 304.

(1) Offshore production facilities under BOEMRE jurisdiction shall report the same annual emissions as calculated and reported by BOEMRE in data collection and emissions estimation study published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication year, report the most recent BOEMRE reported emissions data published by BOEMRE referenced in 30 CFR 250.302 through 304 (GOADS). Adjust emissions based on the operating time for the facility relative to the operating time in the most recent BOEMRE published study.

(ii) [Reserved]

(2) Offshore production facilities that are not under BOEMRE jurisdiction shall use monitoring methods and calculation methodologies published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS).

(i) For any calendar year that does not overlap with the most recent BOEMRE emissions study publication, report the most recent reported emissions data with emissions adjusted based on the operating time for the facility relative to operating time in the previous reporting period.

(ii) [Reserved]

(3) If BOEMRE discontinues or delays their data collection effort by more than 4 years, then offshore reporters shall once in every 4 years use the most recent BOEMRE data collection and emissions estimation methods to report emission from the facility sources.

(4) For either first or subsequent year reporting, offshore facilities either within or outside of BOEMRE jurisdiction that were not covered in the previous BOEMRE data collection cycle shall use the most recent BOEMRE data collection and emissions estimation methods published by BOEMRE referenced in 30 CFR 250.302 through 304 to calculate and report emissions (GOADS) to report emissions.

(t) *Volumetric emissions.* If equation parameters in §98.233 are already at standard conditions, which results in volumetric emissions at standard conditions, then this paragraph does not apply. Calculate volumetric emissions at standard conditions as specified in paragraphs (t)(1) or (2) of this section, with actual pressure and temperature determined by engineering estimates based on best available data unless otherwise specified.

(1) Calculate natural gas volumetric emissions at standard conditions using actual natural gas emission temperature and pressure, and Equation W–33 of this section for conversions of $E_{a,n}$ or conversions of FR_a (whether sub-sonic or sonic).

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \quad \text{(Eq. W-33)}$$

where:

$E_{s,n}$ = Natural gas volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet, except $E_{s,n}$ equals $FR_{s,p}$ for each well p when calculating either subsonic or sonic flowrates under 98.233(g).

$E_{a,n}$ = Natural gas volumetric emissions at actual conditions in cubic feet, except $E_{a,n}$ equals $FR_{a,p}$ for each well p when calculating either subsonic or sonic flowrates under 98.233(g).

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

(2) Calculate GHG volumetric emissions at standard conditions using actual GHG emissions temperature and pressure, and Equation W–34 of this section.

$$E_{s,i} = \frac{E_{a,i} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s} \quad \text{(Eq. W-34)}$$

where:

$E_{s,i}$ = GHG i volumetric emissions at standard temperature and pressure (STP) conditions in cubic feet.

$E_{a,i}$ = GHG i volumetric emissions at actual conditions in cubic feet.

T_s = Temperature at standard conditions (60 °F).

T_a = Temperature at actual emission conditions (°F).

P_s = Absolute pressure at standard conditions (14.7 psia).

P_a = Absolute pressure at actual conditions (psia).

(3) Reporters using 68 °F for standard temperature may use the ratio 519.67/527.67 to convert volumetric emissions from 68 °F to 60 °F.

(u) *GHG volumetric emissions.* Calculate GHG volumetric emissions at standard conditions as specified in paragraphs (u)(1) and (2) of this section, with mole fraction of GHGs in the natural gas determined by engineering estimate based on best available data unless otherwise specified.

(1) Estimate CH_4 and CO_2 emissions from natural gas emissions using Equation W–35 of this section.

$$E_{s,i} = E_{s,n} * M_i \quad \text{(Eq. W-35)}$$

where:

$E_{s,i}$ = GHG i (either CH_4 or CO_2) volumetric emissions at standard conditions in cubic feet.

$E_{s,n}$ = Natural gas volumetric emissions at standard conditions in cubic feet.

M_i = Mole fraction of GHG i in the natural gas.

(2) For Equation W–35 of this section, the mole fraction, M_i, shall be the annual average mole fraction for each sub-basin category or facility, as specified in paragraphs (u)(2)(i) through (vii) of this section.

(i) GHG mole fraction in produced natural gas for onshore petroleum and natural gas production facilities. If you have a continuous gas composition analyzer for produced natural gas, you must use an annual average of these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then you must use an annual average gas composition based on your most recent available analysis of the sub-basin category or facility, as applicable to the emission source.

(ii) GHG mole fraction in feed natural gas for all emissions sources upstream of the de-methanizer or dew point control and GHG mole fraction in facility specific residue gas to transmission pipeline systems for all emissions sources downstream of the demethanizer overhead or dew point control for onshore natural gas processing facilities. For onshore natural gas processing plants that solely fractionate a liquid stream, use the GHG mole percent in feed natural gas liquid for all streams. If you have a continuous gas composition analyzer on feed natural gas, you must use these values for determining the mole fraction. If you do not have a continuous gas composition analyzer, then annual samples must be taken according to methods set forth in § 98.234(b).

(iii) GHG mole fraction in transmission pipeline natural gas that passes through the facility for the onshore natural gas transmission compression industry segment. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(iv) GHG mole fraction in natural gas stored in the underground natural gas storage industry segment. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(v) GHG mole fraction in natural gas stored in the LNG storage industry segment. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(vi) GHG mole fraction in natural gas stored in the LNG import and export industry segment. For export facilities that receive gas from transmission pipelines, you may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(vii) GHG mole fraction in local distribution pipeline natural gas that passes through the facility for natural gas distribution facilities. You may use a default 95 percent methane and 1 percent carbon dioxide fraction for GHG mole fraction in natural gas.

(v) *GHG mass emissions*. Calculate GHG mass emissions in carbon dioxide equivalent by converting the GHG volumetric emissions at standard conditions into mass emissions using Equation W–36 of this section.

$$Mass_i = E_{s,i} * \rho_i * GWP * 10^{-3} \qquad \text{(Eq. W-36)}$$

Where:

$Mass_i$ = GHG_i (either CH_4, CO_2, or N_2O) mass emissions in metric tons CO_2e.

$E_{s,i}$ = GHG_i (either CH_4, CO_2, or N_2O) volumetric emissions at standard conditions, in cubic feet.

P_i = Density of GHG_i. Use 0.0526 kg/ft^3 for CO_2 and N_2O, and 0.0192 kg/ft^3 for CH_4 at 60 °F and 14.7 psia.

GWP = Global warming potential, 1 for CO_2, 25 for CH_4, and 298 for N_2O.

(w) *EOR injection pump blowdown*. Calculate CO_2 pump blowdown emissions as follows:

(1) Calculate the total volume in cubic feet (including pipelines, manifolds and vessels) between isolation valves.

(2) Retain logs of the number of blowdowns per calendar year.

(3) Calculate the total annual venting emissions using Equation W–37 of this section:

$$Mass_{CO2} = N * V_v * R_c * GHG_{CO2} * 10^{-3} \qquad \text{(Eq. W-37)}$$

Where:

$Mass_{CO2}$ = Annual EOR injection gas venting emissions in metric tons from blowdowns.

N = Number of blowdowns for the equipment in the calendar year.

V_v = Total volume in cubic feet of blowdown equipment chambers (including pipelines, manifolds and vessels) between isolation valves.

R_c = Density of critical phase EOR injection gas in kg/ft^3. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice to determine density of super critical EOR injection gas.

GHG_{CO2} = Mass fraction of CO_2 in critical phase injection gas.

1×10^{-3} = Conversion factor from kilograms to metric tons.

(x) EOR hydrocarbon liquids dissolved CO_2. Calculate dissolved CO_2 in hydrocarbon liquids produced through EOR operations as follows:

(1) Determine the amount of CO_2 retained in hydrocarbon liquids after flashing in tankage at STP conditions. Annual samples must be taken according to methods set forth in § 98.234(b) to determine retention of CO_2 in hydrocarbon liquids immediately downstream of the storage tank. Use the annual analysis for the calendar year.

(2) Estimate emissions using Equation W–38 of this section.

$$Mass_{CO2} = S_{hl} * V_{hl} \qquad \text{(Eq. W-38)}$$

Where:

$Mass_{CO2}$ = Annual CO_2 emissions from CO_2 retained in hydrocarbon liquids produced through EOR operations beyond tankage, in metric tons.

S_{hl} = Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

V_{hl} = Total volume of hydrocarbon liquids produced at the EOR operations in barrels in the calendar year.

(y) [Reserved]

(z) *Onshore petroleum and natural gas production and natural gas distribution combustion emissions*. Calculate CO_2, CH_4, and N_2O combustion-related emissions from stationary or portable equipment, except as specified in paragraph (z)(3) and (z)(4) of this section, as follows:

(1) If a fuel combusted in the stationary or portable equipment is listed in Table C–1 of subpart C of this part, or is a blend containing one or more fuels listed in Table C–1, calculate emissions according to (z)(1)(i). If the fuel combusted is natural gas and is of pipeline quality specification and has a minimum high heat value of 950 Btu per standard cubic foot, use the calculation methodology described in (z)(1)(i) and you may use the emission factor provided for natural gas as listed in Table C–1. If the fuel is natural gas, and is not pipeline quality or has a high heat value of less than 950 Btu per standard cubic feet, calculate emissions according to (z)(2). If the fuel is field gas, process vent gas, or a blend containing field gas or process vent gas, calculate emissions according to (z)(2).

(i) For fuels listed in Table C–1 or a blend containing one or more fuels listed in Table C–1, calculate CO_2, CH_4, and N_2O emissions according to any Tier listed in subpart C of this part. You must follow all applicable calculation requirements for that tier listed in 98.33, any monitoring or QA/QC requirements listed for that tier in 98.34, any missing data procedures specified in 98.35, and any recordkeeping requirements specified in 98.37.

(ii) Emissions from fuel combusted in stationary or portable equipment at onshore natural gas and petroleum production facilities and at natural gas distribution facilities will be reported according to the requirements specified in 98.236(c)(19) and not according to the reporting requirements specified in subpart C of this part.

(2) For fuel combustion units that combust field gas, process vent gas, a blend containing field gas or process vent gas, or natural gas that is not of pipeline quality or that has a high heat value of less than 950 Btu per standard cubic feet, calculate combustion emissions as follows:

(i) You may use company records to determine the volume of fuel combusted in the unit during the reporting year.

(ii) If you have a continuous gas composition analyzer on fuel to the combustion unit, you must use these compositions for determining the concentration of gas hydrocarbon constituent in the flow of gas to the unit. If you do not have a continuous gas composition analyzer on gas to the combustion unit, you must use the appropriate gas compositions for each stream of hydrocarbons going to the combustion unit as specified in the applicable paragraph in (u)(2) of this section.

(iii) Calculate GHG volumetric emissions at actual conditions using Equations W–39A and W–39B of this section:

$$E_{a,CO2} = (V_a * Y_{CO2}) \quad + \quad \eta * \sum_{j=1}^{5} V_a * Y_j * R_j \qquad \text{(Eq. W-39A)}$$

$$E_{a,CH4} = V_a * (1-\eta) * Y_{CH4} \qquad \text{(Eq. W-39B)}$$

Where:

$E_{a,CO2}$ = Contribution of annual CO_2 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

V_a = Volume of gas sent to combustion unit in cubic feet, during the year.

Y_{CO2} = Concentration of CO_2 constituent in gas sent to combustion unit.

$E_{a,CH4}$ = Contribution of annual CH_4 emissions from portable or stationary fuel combustion sources in cubic feet, under actual conditions.

η = Fraction of gas combusted for portable and stationary equipment determined using engineering estimation. For internal combustion devices, a default of 0.995 can be used.

Y_j = Concentration of gas hydrocarbon constituents j (such as methane, ethane, propane, butane, and pentanes plus) in gas sent to combustion unit.

R_j = Number of carbon atoms in the gas hydrocarbon constituent j; 1 for methane, 2 for ethane, 3 for propane, 4 for butane, and 5 for pentanes plus, in gas sent to combustion unit.

Y_{CH4} = Concentration of methane constituent in gas sent to combustion unit.

(iv) Calculate GHG volumetric emissions at standard conditions using calculations in paragraph (t) of this section.

(v) Calculate both combustion-related CH_4 and CO_2 mass emissions from volumetric CH_4 and CO_2 emissions using calculation in paragraph (v) of this section.

(vi) Calculate N_2O mass emissions using Equation W–40 of this section.

$$Mass_{N2O} = (1 \times 10^{-3}) \times Fuel \times HHV \times EF \times GWP \qquad \text{(Eq. W-40)}$$

Where:

$Mass_{N2O}$ = Annual N_2O emissions from the combustion of a particular type of fuel (metric tons CO_2e).

Fuel = Mass or volume of the fuel combusted (mass or volume per year, choose appropriately to be consistent with the units of HHV).

HHV = For the higher heating value for field gas or process vent gas, use 1.235×10^{-3} mmBtu/scf for HHV.

EF = Use 1.0×10^{-4} kg N_2O/mmBtu.

1×10^{-3} = Conversion factor from kilograms to metric tons.

GWP = Global warming potential, as listed in Table A–1 of subpart A of this part.

(3) External fuel combustion sources with a rated heat capacity equal to or less than 5 mmBtu/hr do not need to report combustion emissions or include these emissions for threshold determination in § 98.231(a). You must report

the type and number of each external fuel combustion unit.

(4) Internal fuel combustion sources, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr (or the equivalent of 130 horsepower), do not need to report combustion emissions or include these emissions for threshold determination in §98.231(a). You must report the type and number of each internal fuel combustion unit.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80575, Dec. 23, 2011; 77 FR 51490, Aug. 24, 2012; 78 FR 71960, Nov. 29, 2013]

§ 98.234 Monitoring and QA/QC requirements.

The GHG emissions data for petroleum and natural gas emissions sources must be quality assured as applicable as specified in this section. Offshore petroleum and natural gas production facilities shall adhere to the monitoring and QA/QC requirements as set forth in 30 CFR 250.

(a) You must use any of the methods described as follows in this paragraph to conduct leak detection(s) of equipment leaks and through-valve leakage from all source types listed in §98.233(k), (o), (p) and (q) that occur during a calendar year, except as provided in paragraph (a)(4) of this section.

(1) *Optical gas imaging instrument.* Use an optical gas imaging instrument for equipment leak detection in accordance with 40 CFR part 60, subpart A, §60.18 of the *Alternative work practice for monitoring equipment leaks*, §60.18(i)(1)(i); §60.18(i)(2)(i) except that the monitoring frequency shall be annual using the detection sensitivity level of 60 grams per hour as stated in 40 CFR Part 60, subpart A, Table 1: *Detection Sensitivity Levels;* §60.18(i)(2)(ii) and (iii) except the gas chosen shall be methane, and §60.18(i)(2)(iv) and (v); §60.18(i)(3); §60.18(i)(4)(i) and (v); including the requirements for daily instrument checks and distances, and excluding requirements for video records. Any emissions detected by the optical gas imaging instrument is a leak unless screened with Method 21 (40 CFR part 60, appendix A–7) monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the optical gas imaging instrument to image the source types required by this subpart in accordance with the instrument manufacturer's operating parameters. Unless using methods in paragraph (a)(2) of this section, an optical gas imaging instrument must be used for all source types that are inaccessible and cannot be monitored without elevating the monitoring personnel more than 2 meters above a support surface.

(2) *Method 21.* Use the equipment leak detection methods in 40 CFR part 60, appendix A–7, Method 21. If using Method 21 monitoring, if an instrument reading of 10,000 ppm or greater is measured, a leak is detected. Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. Owners or operators must use alternative leak detection devices as described in paragraph (a)(1) or (a)(2) of this section to monitor inaccessible equipment leaks or vented emissions.

(3) *Infrared laser beam illuminated instrument.* Use an infrared laser beam illuminated instrument for equipment leak detection. Any emissions detected by the infrared laser beam illuminated instrument is a leak unless screened with Method 21 monitoring, in which case 10,000 ppm or greater is designated a leak. In addition, you must operate the infrared laser beam illuminated instrument to detect the source types required by this subpart in accordance with the instrument manufacturer's operating parameters.

(4) [Reserved]

(5) *Acoustic leak detection device.* Use the acoustic leak detection device to detect through-valve leakage. When using the acoustic leak detection device to quantify the through-valve leakage, you must use the instrument manufacturer's calculation methods to quantify the through-valve leak. When using the acoustic leak detection device, if a leak of 3.1 scf per hour or greater is calculated, a leak is detected. In addition, you must operate the acoustic leak detection device to monitor the source valves required by this subpart in accordance with the instrument manufacturer's operating parameters. Acoustic stethoscope type devices designed to detect through valve leakage when put in contact with

the valve body and that provide an audible leak signal but do not calculate a leak rate can be used to identify nonleakers with subsequent measurement required to calculate the rate if through-valve leakage is identified. Leaks are reported if a leak rate of 3.1 scf per hour or greater is measured.

(b) You must operate and calibrate all flow meters, composition analyzers and pressure gauges used to measure quantities reported in § 98.233 according to the procedures in § 98.3(i) and the procedures in paragraph (b) of this section. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or you may use an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(c) Use calibrated bags (also known as vent bags) only where the emissions are at near-atmospheric pressures and below the maximum temperature specified by the vent bag manufacturer such that the bag is safe to handle. The bag opening must be of sufficient size that the entire emission can be tightly encompassed for measurement till the bag is completely filled.

(1) Hold the bag in place enclosing the emissions source to capture the entire emissions and record the time required for completely filling the bag. If the bag inflates in less than one second, assume one second inflation time.

(2) Perform three measurements of the time required to fill the bag, report the emissions as the average of the three readings.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in § 98.233(t).

(4) Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).

(d) Use a high volume sampler to measure emissions within the capacity of the instrument.

(1) A technician following manufacturer instructions shall conduct measurements, including equipment manufacturer operating procedures and measurement methodologies relevant to using a high volume sampler, including positioning the instrument for complete capture of the equipment leak without creating backpressure on the source.

(2) If the high volume sampler, along with all attachments available from the manufacturer, is not able to capture all the emissions from the source then use anti-static wraps or other aids to capture all emissions without violating operating requirements as provided in the instrument manufacturer's manual.

(3) Estimate natural gas volumetric emissions at standard conditions using calculations in § 98.233(t). Estimate CH_4 and CO_2 volumetric and mass emissions from volumetric natural gas emissions using the calculations in § 98.233(u) and (v).

(4) Calibrate the instrument at 2.5 percent methane with 97.5 percent air and 100 percent CH_4 by using calibrated gas samples and by following manufacturer's instructions for calibration.

(e) Peng Robinson Equation of State means the equation of state defined by Equation W–41 of this section:

$$p = \frac{RT}{V_m - b} - \frac{a\alpha}{V_m^2 + 2bV_m - b^2} \qquad \text{(Eq. W-41)}$$

Where:

p = Absolute pressure.

R = Universal gas constant.

T = Absolute temperature.

V_m = Molar volume.

$$a = \frac{0.45724 R^2 T_c^2}{p_c}$$

$$b = \frac{0.7780 R T_c}{p_c}$$

$$\alpha = \left(1 + \left(0.37464 + 1.54226\omega - 0.26992\omega^2\right)\left(1 - \sqrt{\frac{T}{T_c}}\right)\right)^2$$

Where:

ω = Acentric factor of the species.

T_c = Critical temperature.

P_c = Critical pressure.

(f) *Special reporting provisions*—(1) *Best available monitoring methods.* EPA will allow owners or operators to use best available monitoring methods for parameters in § 98.233 Calculating GHG Emissions as specified in paragraphs (f)(2), (f)(3), and (f)(4) of this section. If the reporter anticipates the potential need for best available monitoring for sources for which they need to petition EPA and the situation is unresolved at the time of the deadline, reporters should submit written notice of this potential situation to EPA by the specified deadline for requests to be considered. EPA reserves the right to review best available monitoring method requests submitted after the deadlines specified in this section, and will consider requests which demonstrate unique or unusual circumstances unforeseen at the time of the applicable best available monitoring method deadline. The Administrator reserves the right to request further information in regard to all petition requests. The owner or operator must use the calculation methodologies and equations in § 98.233 Calculating GHG Emissions. Best available monitoring methods means any of the following methods specified in paragraph (f)(1) of this section:

(i) Monitoring methods currently used by the facility that do not meet the specifications of this subpart.

(ii) Supplier data.

(iii) Engineering calculations.

(iv) Other company records.

(2) *Best available monitoring methods for well-related emissions.* During January 1, 2011 through December 31, 2011, owners and operators may use best available monitoring methods for any well-related data that cannot reasonably be measured according to the monitoring and QA/QC requirements of this subpart. These well-related sources are:

(i) Gas well venting during well completions and workovers with hydraulic fracturing as specified in § 98.233(g).

(ii) Well testing venting and flaring as specified in § 98.233(l).

(3) *Best available monitoring methods for specified activity data.* During January 1, 2011 through December 31, 2011, owners or operators may use best available monitoring methods for activity data as listed below that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this subpart. These sources are:

(i) Cumulative hours of venting, days, or times of operation in § 98.233(e), (f), (g), (h), (l), (o), (p), (q), and (r).

(ii) Number of blowdowns, completions, workovers, or other events in § 98.233(f), (g), (h), (i), and (w).

(iii) Cumulative volume produced, volume input or output, or volume of fuel used in paragraphs § 98.233(d), (e), (j), (k), (l), (m), (n), (x), (y), and (z).

(4) *Best available monitoring methods for leak detection and measurement.* During January 1, 2011 through December 31, 2011, owners or operators may use best available monitoring methods for sources requiring leak detection and/or measurement that cannot reasonably be obtained according to the monitoring and QA/QC requirements of this part. These sources include:

(i) Reciprocating compressor rod packing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in § 98.232(d)(1), (e)(1), (f)(1), (g)(1), and (h)(1).

(ii) Centrifugal compressor wet seal oil degassing venting in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, and LNG import and export equipment as specified in § 98.232(d)(2), (e)(2), (f)(2), (g)(2), and (h)(2).

(iii) Acid gas removal vent stacks in onshore petroleum and natural gas production and onshore natural gas processing as specified in § 98.232(c)(17) and (d)(6).

(iv) Equipment leak emissions from valves, connectors, open ended lines, pressure relief valves, block valves, control valves, compressor blowdown valves, orifice meters, other meters, regulators, vapor recovery compressors, centrifugal compressor dry seals, and/or other equipment leaks in onshore natural gas processing, onshore natural gas transmission compression, underground natural gas storage, LNG storage, LNG import and export equipment, and natural gas distribution as specified in § 98.232(d)(7), (e)(7), (f)(5), (g)(3), (h)(4), and (i)(1).

(v) Condensate (oil and/or water) storage tanks in onshore natural gas transmission compression as specified in § 98.232(e)(3).

(5) *Requests for the use of best available monitoring methods.* (i) No request or approval by the Administrator is necessary to use best available monitoring methods between January 1, 2011 and December 31, 2011 for the sources specified in paragraph (f)(2) of this section.

(ii) No request or approval by the Administrator is necessary to use best available monitoring methods between January 1, 2011 and December 31, 2011 for sources specified in paragraph (f)(3) of this section.

(iii) No request or approval by the Administrator is necessary to use best available monitoring methods between January 1, 2011 and December 31, 2011 for sources specified in paragraph (f)(4) of this section.

(iv) No request or approval by the Administrator is necessary to use best available monitoring methods for data that cannot reasonably be obtained between January 1, 2011 and December 31, 2011 for sources not listed in paragraph (f)(2), (f)(3), and (f)(4) of this section.

(6)–(7) [Reserved]

(8) *Requests for extension of the use of best available monitoring methods beyond 2011 for sources listed in paragraphs (f)(2), (f)(3), (f)(4), and (f)(5)(iv) of this section*—(i) *Timing of request.* EPA does not anticipate a need for best available monitoring methods beyond 2011, but for all reporting years after 2011, best available monitoring methods will be considered for unique or unusual circumstances which include data collection methods that do not meet safety regulations, technical infeasibility, or counter to other local, State, or Federal regulations. For use of best available monitoring methods in 2012, an initial notice of intent to request best available monitoring methods must be submitted by December 31, 2011. Any notice of intent submitted prior to the effective date of this rule cannot be used to meet this December 31, 2011 deadline; a new notice of intent must be signed and submitted by the designated representative. In addition to the initial notification of intent, owners or operators must also submit an extension request containing the information specified in 98.234(f)(8)(ii) by March 30, 2012. Any best available monitoring methods request submitted prior to the effective date of this rule cannot be used to meet the March 30, 2012 deadline; a new best available monitoring methods request must be signed and submitted by the designated representative. Owners or operators that submit both a timely notice of intent and extension request consistent with 98.234(f)(8)(ii) can automatically use best available monitoring method

through June 30, 2012, for the specific parameters identified in their notification of intent and best available monitoring methods request regardless of whether the best available monitoring methods request is ultimately approved. Owners or operators that submit a notice of intent but do not follow up with a best available monitoring methods request by March 30, 2012 cannot use best available monitoring methods in 2012. For 2012, when an owner or operator has submitted a notice of intent and a subsequent best available monitoring method extension request, use of best available monitoring methods will be valid, upon approval by the Administrator, until the date indicated in the approval or until December 31, 2012, whichever is earlier. For reporting years after 2012, a new request to use best available monitoring methods must be submitted by June 30th of the year prior to the reporting year for which use of best available monitoring methods is sought.

(ii) *Content of request.* Requests must contain the following information:

(A) A list of specific source categories and parameters for which the owner or operator is seeking use of best available monitoring methods.

(B) For each specific source for which an owner or operator is requesting use of best available monitoring methods, a description of the unique or unusual circumstances, such as data collection methods that do not meet safety regulations, technical infeasibility, or specific laws or regulations that are counter to data collection methods that conflict with each specific source.

(C) A detailed explanation and supporting documentation of how and when the owner or operator will comply with all of the subpart W reporting requirements for which use of best available monitoring methods are sought.

(iii) *Approval criteria.* To obtain approval to use best available monitoring methods after December 31, 2011, the owner or operator must submit a request demonstrating to the Administrator's satisfaction that the owner or operator faces unique or unusual circumstances which include, by way of example and not in limitation, clearly demonstrated data collection methods that do not meet safety regulations, technical infeasibility, or counter to other local, State, or Federal regulations, along with the reasons the owner or operator cannot otherwise address the unique or unusual circumstances as required to be demonstrated in this paragraph.

(g) For the purposes of fulfilling requirements in 40 CFR 98.233(f) and (g) which require measurements to be taken every other year beginning in the first year of data collection, reporters have the option of taking the first measurement in 2012 to satisfy the requirements for the 2011–2012 data collection cycle.

(h) [Reserved]

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 22827, Apr. 25, 2011; 76 FR 59540, Sept. 27, 2011; 76 FR 80586, Dec. 23, 2011; 78 FR 25395, May 1, 2013]

§ 98.235 Procedures for estimating missing data.

A complete record of all estimated and/or measured parameters used in the GHG emissions calculations is required. If data are lost or an error occurs during annual emissions estimation or measurements, you must repeat the estimation or measurement activity for those sources as soon as possible, including in the subsequent calendar year if missing data are not discovered until after December 31 of the year in which data are collected, until valid data for reporting is obtained. Data developed and/or collected in a subsequent calendar year to substitute for missing data cannot be used for that subsequent year's emissions estimation. Where missing data procedures are used for the previous year, at least 30 days must separate emissions estimation or measurements for the previous year and emissions estimation or measurements for the current year of data collection. For missing data which are continuously monitored or measured, (for example flow meters), or for missing temperature or pressure data that are required under § 98.236, the reporter may use best available data for use in emissions determinations. The reporter must record and report the basis for the best available data in these cases.

§98.236 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain reported emissions and related information as specified in this section.

(a) Report annual emissions in metric tons of CO_2e for each GHG separately for each of the industry segments listed in paragraphs (a)(1) through (8) of this section.

(1) Onshore petroleum and natural gas production.

(2) Offshore petroleum and natural gas production.

(3) Onshore natural gas processing.

(4) Onshore natural gas transmission compression.

(5) Underground natural gas storage.

(6) LNG storage.

(7) LNG import and export.

(8) Natural gas distribution.

(b) For offshore petroleum and natural gas production, report emissions of CH_4, CO_2, and N_2O as applicable to the source type (in metric tons CO_2e per year at standard conditions) individually for all of the emissions source types listed in the most recent BOEMRE study.

(c) Report the information listed in this paragraph for each applicable source type in metric tons of CO_2e for each GHG. If a facility operates under more than one industry segment, each piece of equipment should be reported under the unit's respective majority use segment. When a source type listed under this paragraph routes gas to flare, separately report the emissions that were vented directly to the atmosphere without flaring, and the emissions that resulted from flaring the gas. Both the vented and flared emissions will be reported under the respective source type and not under the flare source type.

(1) For natural gas pneumatic devices (refer to Equation W–1 of §98.233), report the following:

(i) Actual count and estimated count separately of natural gas pneumatic high bleed devices as applicable.

(ii) Actual count and estimated count separately of natural gas pneumatic low bleed devices as applicable.

(iii) Actual count and estimated count separately of natural gas pneumatic intermittent bleed devices as applicable.

(iv) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons CO_2e for each gas, for each of the following pieces of equipment: high bleed pneumatic devices; intermittent bleed pneumatic devices; low bleed pneumatic devices.

(2) For natural gas driven pneumatic pumps (refer to Equation W–2 of §98.233), report the following,

(i) Count of natural gas driven pneumatic pumps.

(ii) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons CO_2e for each gas, for all natural gas driven pneumatic pumps combined.

(3) For each acid gas removal unit (refer to Equation W–3 and Equation W–4 of §98.233), report the following:

(i) Total throughput off the acid gas removal unit using a meter or engineering estimate based on process knowledge or best available data in million cubic feet per year.

(ii) For Calculation Methodology 1 and Calculation Methodology 2 of §98.233(d), annual average fraction of CO_2 content in the vent from the acid gas removal unit (refer to §98.233(d)(6)).

(iii) For Calculation Methodology 3 of §98.233(d), annual average volume fraction of CO_2 content of natural gas into and out of the acid gas removal unit (refer to §98.233(d)(7) and (d)(8)).

(iv) Report the annual quantity of CO_2, expressed in metric tons CO_2e, that was recovered from the AGR unit and transferred outside the facility, under subpart PP of this part.

(v) Report annual CO_2 emissions for the AGR unit, expressed in metric tons CO_2e.

(vi) For the onshore natural gas processing industry segment only, report a unique name or ID number for the AGR unit.

(vii) An indication of which calculation methodology was used for the AGR.

(4) For dehydrators, report the following:

(i) For each Glycol dehydrator with a throughput greater than or equal to 0.4 MMscfd (refer to §98.233(e)(1)), report the following:

(A) Glycol dehydrator feed natural gas flow rate in MMscfd, determined by engineering estimate based on best available data.

(B) Glycol dehydrator absorbent circulation pump type.

(C) Whether stripper gas is used in glycol dehydrator.

(D) Whether a flash tank separator is used in glycol dehydrator.

(E) Type of absorbent.

(F) Total time the glycol dehydrator is operating in hours.

(G) Temperature, in degrees Fahrenheit and pressure, in psig, of the wet natural gas.

(H) Concentration of CH_4 and CO_2 in wet natural gas.

(I) What vent gas controls are used (refer to § 98.233(e)(3) and (e)(4)).

(J) For each glycol dehydrator, report annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2e for each gas.

(K) For each glycol dehydrator, report annual CO_2, CH_4, and N_2O emissions that resulted from flaring process gas from the dehydrator, expressed in metric tons CO_2e for each gas.

(L) For the onshore natural gas processing industry segment only, report a unique name or ID number for glycol dehydrator.

(ii) For all glycol dehydrators with a throughput less than 0.4 MMscfd (refer to § 98.233, Equation W–5 of § 98.233), report the following:

(A) Count of glycol dehydrators.

(B) Which vent gas controls are used (refer to § 98.233(e)(3) and (e)(4)).

(C) Report annual CO_2 and CH_4 emissions at the facility level that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2e for each gas, combined for all glycol dehydrators with annual average daily throughput of less than 0.4 MMscfd.

(D) Report annual CO_2, CH_4, and N_2O emissions at the facility level that resulted from the flaring of process gas, expressed in metric tons CO_2e for each gas, combined for all glycol dehydrators with annual average daily throughput of less than 0.4 MMscfd.

(iii) For absorbent desiccant dehydrators (refer to Equation W–6 of § 98.233), report the following:

(A) Count of desiccant dehydrators.

(B) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons CO_2e for each gas, for all absorbent desiccant dehydrators combined.

(5) For well venting for liquids unloading, report the following:

(i) For Calculation Methodology 1 (refer to Equation W–7 of § 98.233), report the following for each tubing diameter group and pressure group combination within each sub-basin category:

(A) Count of wells vented to the atmosphere for liquids unloading.

(B) Count of plunger lifts. Whether the selected well from the tubing diameter and pressure group combination had a plunger lift (yes/no).

(C) Cumulative number of unloadings vented to the atmosphere.

(D) Average flow rate of the measured well venting in cubic feet per hour (refer to § 98.233(f)(1)(i)(A)).

(E) Internal casing diameter or internal tubing diameter in inches, where applicable, and well depth of each well, in feet, selected to represent emissions in that tubing size and pressure combination.

(F) Casing pressure, in psia, of each well selected to represent emissions in that tubing size group and pressure group combination that does not have a plunger lift.

(G) Tubing pressure, in psia, of each well selected to represent emissions in a tubing size group and pressure group combination that has a plunger lift.

(H) Report annual CO_2 and CH_4 emissions, expressed in metric tons CO_2e for each gas.

(ii) For Calculation Methodologies 2 and 3 (refer to Equation W–8 and W–9 of § 98.233), report the following for each sub-basin category:

(A) Count of wells vented to the atmosphere for liquids unloading.

(B) Count of plunger lifts.

(C) Cumulative number of unloadings vented to the atmosphere.

(D) Average internal casing diameter, in inches, for all wells, where applicable.

(E) Report annual CO_2 and CH_4 emissions, expressed in metric tons CO_2e for each GHG gas.

(6) For well completions and workovers, report the following for each sub-basin category:

(i) For gas well completions and workovers with hydraulic fracturing by sub-basin and well type (horizontal or vertical) combination (refer to Equation W–10A and W–10B of § 98.233), report the following:

(A) Total count of completions in calendar year.

(B) When using Equation W–10A, measured flow rate of backflow during well completion in standard cubic feet per hour.

(C) Total count of workovers in calendar year that flare gas or vent gas to the atmosphere.

(D) When using Equation W–10A, measured flow rate of backflow during well workover in standard cubic feet per hour.

(E) When using Equation W–10A, total number of days of backflow from all wells during completions.

(F) When using Equation W–10A, total number of days of backflow from all wells during workovers.

(G) Report number of completions employing purposely designed equipment that separates natural gas from the backflow and the amount of natural gas, in standard cubic feet, recovered using engineering estimate based on best available.

(H) Report number of workovers employing purposely designed equipment that separates natural gas from the backflow and the amount of natural gas, in standard cubic feet, recovered using engineering estimate based on best available data.

(I) Annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2e for each gas.

(J) Annual CO_2, CH_4, and N_2O emissions that resulted from flares, expressed in metric tons CO_2e for each gas.

(ii) For gas well completions and workovers without hydraulic fracturing (refer to Equation W–13 of § 98.233):

(A) Total count of completions in calendar year.

(B) Total count of workovers in calendar year that flare gas or vent gas to the atmosphere.

(C) Total number of days of gas venting to the atmosphere during backflow for completion.

(D) Annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2e for each gas.

(E) Annual CO_2, CH_4, and N_2O emissions that resulted from flares, expressed in metric tons CO_2e for each gas.

(7) For blowdown vent stack emission source, (refer to Equation W–14A and Equation W–14B of § 98.233), report the following:

(i) For each unique physical volume that is blown down more than once during the calendar year, report the following:

(A) Total number of blowdowns for each unique physical volume in the calendar year.

(B) Annual CO_2 and CH_4 emissions, for each unique physical blowdown volume, expressed in metric tons CO_2e for each gas.

(C) A unique name or ID number for the unique physical volume.

(ii) For all unique volumes that are blown down once during the calendar year, report the following:

(A) Total number of blowdowns for all unique physical volumes in the calendar year.

(B) Annual CO_2 and CH_4 emissions from all unique physical volumes as an aggregate per facility, expressed in metric tons CO_2e for each gas.

(8) For gas emitted from produced oil sent to atmospheric tanks:

(i) For wellhead gas-liquid separator with oil throughput greater than or equal to 10 barrels per day, using Calculation Methodology 1 and 2 of § 98.233(j), report the following by sub-basin category, unless otherwise specified:

(A) Number of wellhead separators sending oil to atmospheric tanks.

(B) Estimated average separator temperature, in degrees Fahrenheit, and estimated average pressure, in psig.

(C) Estimated average sales oil stabilized API gravity, in degrees.

(D) Count of hydrocarbon tanks at well pads.

(E) Best estimate of count of stock tanks not at well pads receiving your oil.

(F) Total volume of oil from all wellhead separators sent to tank(s) in barrels per year.

(G) Count of tanks with emissions control measures, either vapor recovery system or flaring, for tanks at well pads.

(H) Best estimate of count of stock tanks assumed to have emissions control measures not at well pads, receiving your oil.

(I) Range of concentrations of flash gas, CH_4 and CO_2.

(J) Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO_2e for each gas, for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 1, and for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 2 of § 98.233(j).

(K) Annual CO_2 and CH_4 gas quantities that were recovered, expressed in metric tons CO_2e for each gas, for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 1, and for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 2 of § 98.233(j).

(L) Annual CO_2, CH_4, and N_2O emissions that resulted from flaring gas, expressed in metric tons CO_2e for each gas, for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 1, and for all wellhead gas-liquid separators or storage tanks using Calculation Methodology 2 of § 98.233(j).

(ii) For wells with oil production greater than or equal to 10 barrels per day, using Calculation Methodology 3 and 4 of § 98.233(j), report the following by sub-basin category:

(A) Total volume of sales oil from all wells in barrels per year.

(B) Total number of wells sending oil directly to tanks.

(C) Total number of wells sending oil to separators off the well pads.

(D) Sales oil API gravity range for wells in (c)(8)(ii)(B) and (c)(8)(ii)(C) of this section, in degrees.

(E) Count of hydrocarbon tanks on wellpads.

(F) Count of hydrocarbon tanks, both on and off well pads assumed to have emissions control measures: either vapor recovery system or flaring of tank vapors.

(G) Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO_2e for each gas, at the sub-basin level for Calculation Methodology 3 or 4 of § 98.233(j).

(H) Annual CO_2 and CH_4 gas quantities that were recovered, expressed in metric tons CO_2e for each gas, at the sub-basin level for Calculation Methodology 3 or 4 of § 98.233(j).

(I) Annual CO_2, CH_4, and N_2O emissions that resulted from flaring gas, expressed in metric tons CO_2e for each gas, at the sub-basin level for Calculation Methodology 3 and 4 of § 98.233(j).

(iii) For wellhead gas-liquid separators and wells with throughput less than 10 barrels per day, using Calculation Methodology 5 of § 98.233(j) Equation W–15 of § 98.233, report the following:

(A) Number of wellhead separators.

(B) Number of wells without wellhead separators.

(C) Total volume of oil production in barrels per year.

(D) Best estimate of fraction of production sent to tanks with assumed control measures: either vapor recovery system or flaring of tank vapors.

(E) Count of hydrocarbon tanks on well pads.

(F) Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO_2e for each gas, at the sub-basin level for Calculation Methodology 5 of § 98.233(j).

(G) Annual CO_2 and CH_4 gas quantities that were recovered, expressed in metric tons CO_2e for each gas, at the sub-basin level for Calculation Methodology 5 of § 98.233(j).

(H) Annual CO_2, CH_4, and N_2O emissions that resulted from flaring gas, expressed in metric tons CO_2e for each gas, at the sub-basin level for Calculation Methodology 5 of § 98.233(j).

(iv) If wellhead separator dump valve is functioning improperly during the calendar year (refer to Equation W–16 of § 98.233), report the following:

(A) Count of wellhead separators that dump valve factor is applied.

(B) Annual CO_2 and CH_4 emissions that resulted from venting gas to the atmosphere, expressed in metric tons CO_2e for each gas, at the sub-basin level for improperly functioning dump valves.

(9) For transmission tank emissions identified in § 98.233(k) from scrubber dump valves report the following:

(i) For each vent stack, report annual CO_2 and CH_4 emissions that resulted from venting gas directly to the atmosphere, expressed in metric tons CO_2e for each gas.

(ii) For each transmission storage tank, report annual CO_2, CH_4, and N_2O emissions that resulted from flaring process gas from the transmission storage tank, expressed in metric tons CO_2e for each gas.

(iii) A unique name or ID number for the vent stack monitored according to 40 CFR 98.233(k).

(10) For well testing venting and flaring (refer to Equation W–17A or W–17B of § 98.233), report the following:

(i) Number of wells tested per basin in calendar year.

(ii) Average gas to oil ratio for each basin.

(iii) Average number of days the well is tested in a basin.

(iv) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons CO_2e for each gas, emissions from well testing venting.

(v) Report annual CO_2, CH_4, and N_2O emissions at the facility level, expressed in metric tons CO_2e for each gas, emissions from well testing flaring.

(11) For associated natural gas venting and flaring (refer to Equation W–18 of § 98.233), report the following for each basin:

(i) Number of wells venting or flaring associated natural gas in a calendar year.

(ii) Average gas to oil ratio for each basin.

(iii) Report annual CO_2 and CH_4 emissions at the facility level, expressed in metric tons CO_2e for each gas, emissions from associated natural gas venting.

(iv) Report annual CO_2, CH_4, and N_2O emissions at the facility level, expressed in metric tons CO_2e for each gas, emissions from associated natural gas flaring.

(12) For flare stacks (refer to Equation W–19, W–20, and W–21 of § 98.233), report the following for each flare:

(i) Whether flare has a continuous flow monitor.

(ii) Volume of gas sent to flare in cubic feet per year.

(iii) Percent of gas sent to un-lit flare determined by engineering estimate and process knowledge based on best available data and operating records.

(iv) Whether flare has a continuous gas analyzer.

(v) Flare combustion efficiency.

(vi) Report uncombusted CH_4 emissions, in metric tons CO_2e (refer to Equation W–19 of § 98.233).

(vii) Report uncombusted CO_2 emissions, in metric tons CO_2e (refer to Equation W–20 of § 98.233).

(viii) Report combusted CO_2 emissions, in metric tons CO_2e (refer to Equation W–21 of § 98.233).

(ix) Report N_2O emissions, in metric tons CO_2e.

(x) For the natural gas processing industry segment, a unique name or ID number for the flare stack.

(xi) In the case that a CEMS is used to measure CO_2 emissions for the flare stack, indicate that a CEMS was used in the annual report and report the combusted CO_2 and uncombusted CO_2 as a combined number.

(13) For each centrifugal compressor:

(i) For compressors with wet seals in operational mode (refer to Equations W–22 through W–24 of § 98.233), report the following for each degassing vent:

(A) Number of wet seals connected to the degassing vent.

(B) Fraction of vent gas recovered for fuel or sales or flared.

(C) Annual throughput in million scf, use an engineering calculation based on best available data.

(D) Type of meters used for making measurements.

(E) Reporter emission factor for wet seal oil degassing vents in cubic feet per hour (refer to Equation W–24 of § 98.233).

(F) Total time the compressor is operating in hours.

(G) Report seal oil degassing vent emissions for compressors measured and for compressors not measured in metric tons of CO_2e for each gas.

(ii) For wet and dry seal centrifugal compressors in operating mode, (refer to Equations W–22 through W–24 of §98.233), report the following:

(A) Total time in hours the compressor is in operating mode.

(B) Reporter emission factor for blowdown vents in cubic feet per hour (refer to Equation W–24 of §98.233).

(C) Report blowdown vent emissions when in operating mode in metric tons of CO_2e for each gas.

(iii) For wet and dry seal centrifugal compressors in not operating, depressurized mode (refer to Equations W–22 through W–24 of §98.233), report the following:

(A) Total time in hours the compressor is in shutdown, depressurized mode.

(B) Reporter emission factor for isolation valve emissions in shutdown, depressurized mode in cubic feet per hour (refer to Equation W–24 of §98.233).

(C) Report the isolation valve leakage emissions in not operating, depressurized mode in metric tons of CO_2e for each gas.

(iv) Report total annual compressor emissions from all modes of operation in metric tons of CO_2e for each gas.

(v) For centrifugal compressors in onshore petroleum and natural gas production (refer to Equation W–25 of §98.233), report the following:

(A) Count of compressors.

(B) Report annual emissions in metric tons of CO_2e for each gas (refer to Equation W–25 of §98.233) collectively.

(14) For reciprocating compressors:

(i) For reciprocating compressors rod packing emissions with or without a vent in operating mode, report the following:

(A) Annual throughput in million scf, use an engineering calculation based on best available data.

(B) Total time in hours the reciprocating compressor is in operating mode.

(C) Report rod packing emissions for compressors measured and for compressors not measured in metric tons of CO_2e for each gas.

(ii) For reciprocating compressors blowdown vents not manifold to rod packing vents, in operating and standby pressurized mode (refer to Equations W–26 through W–28 of §98.233), report the following:

(A) Total time in hours the compressor is in standby, pressurized mode.

(B) Reporter emission factor for blowdown vents in cubic feet per hour (refer to §98.233, Equation W–28).

(C) Report blowdown vent emissions when in operating and standby pressurized modes in metric tons of CO_2e for each gas.

(iii) For reciprocating compressors in not operating, depressurized mode (refer to Equations W–26 through W–28 of §98.233), report the following:

(A) Total time the compressor is in not operating, depressurized mode.

(B) Reporter emission factor for isolation valve emissions in not operating, depressurized mode in cubic feet per hour (refer to Equation W–28 of §98.233).

(C) Report isolation valve leakage emissions in not operating, depressurized mode in metric tons of CO_2e for each gas.

(iv) Report total annual compressor emissions from all modes of operation in metric tons of CO_2e for each gas.

(v) For reciprocating compressors in onshore petroleum and natural gas production (refer to Equation W–29 of §98.233), report the following:

(A) Count of compressors.

(B) Report annual emissions in metric tons of CO_2e for each gas collectively (refer to Equation W–29 of §98.233).

(15) For each component type (major equipment type for onshore production) that uses emission factors for estimating emissions (refer to §98.233(q) and (r))

(i) For equipment leaks found in each leak survey (refer to §98.233(q)), report the following:

(A) Total count of leaks found in each complete survey listed by date of survey and each component type for which there is a leaker emission factor in Tables W–2, W–3, W–4, W–5, W–6, and W–7 of this subpart.

(B) For onshore natural gas processing, range of concentrations of CH_4 and CO_2 (refer to Equation W–30A of §98.233).

(C) Annual CO_2 and CH_4 emissions in metric tons CO_2e for each gas (refer to

Equation W–30A of § 98.233), by component type.

(ii) For equipment leaks calculated using population counts and factors (refer to § 98.233(r)), report the following:

(A) For source categories § 98.230(a)(5), (a)(6), and (a)(7), total count for each component type in Tables W–4, W–5, and W–6 of this subpart for which there is a population emission factor, listed by major heading and component type.

(B) For onshore production (refer to § 98.230 paragraph (a)(2)), total count for each type of major equipment in Table W–1B and Table W–1C of this subpart, by facility.

(C) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas (refer to Equation W–31 of § 98.233), by component type.

(16) For local distribution companies, report the following:

(i) Total number of above grade T–D transfer stations in the facility.

(ii) Number of years over which all T–D transfer stations will be monitored at least once.

(iii) Number of T–D stations monitored in calendar year.

(iv) Total number of below grade T–D transfer stations in the facility.

(v) Total number of above grade metering-regulating stations (this count will include above grade T–D transfer stations) in the facility.

(vi) Total number of below grade metering-regulating stations (this count will include below grade T–D transfer stations) in the facility.

(vii) [Reserved]

(viii) Leak factor for meter/regulator run developed in Equation W–32 of § 98.233.

(ix) Number of miles of unprotected steel distribution mains.

(x) Number of miles of protected steel distribution mains.

(xi) Number of miles of plastic distribution mains.

(xii) Number of miles of cast iron distribution mains.

(xiii) Number of unprotected steel distribution services.

(xiv) Number of protected steel distribution services.

(xv) Number of plastic distribution services.

(xvi) Number of copper distribution services.

(xvii) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all above grade T–D transfer stations combined.

(xviii) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all below grade T–D transfer stations combined.

(xix) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all above grade metering-regulating stations (including T–D transfer stations) combined.

(xx) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all below grade metering-regulating stations (including T–D transfer stations) combined.

(xxi) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all distribution mains combined.

(xxii) Annual CO_2 and CH_4 emissions, in metric tons CO_2e for each gas, from all distribution services combined.

(17) For each EOR injection pump blowdown (refer to Equation W–37 of § 98.233), report the following:

(i) Pump capacity, in barrels per day.

(ii) Volume of critical phase gas between isolation valves.

(iii) Number of blowdowns per year.

(iv) Critical phase EOR injection gas density.

(v) For each EOR pump, report annual CO_2 emissions, expressed in metric tons CO_2e for each gas.

(18) For EOR hydrocarbon liquids dissolved CO_2 for each sub-basin category (refer to Equation W–38 of § 98.233), report the following:

(i) Volume of crude oil produced in barrels per year.

(ii) Amount of CO_2 retained in hydrocarbon liquids in metric tons per barrel, under standard conditions.

(iii) Report annual CO_2 emissions at the sub-basin level, expressed in metric tons CO_2e.

(19) For onshore petroleum and natural gas production and natural gas distribution combustion emissions, report the following:

(i) Cumulative number of external fuel combustion units with a rated heat capacity equal to or less than 5 mmBtu/hr, by type of unit.

(ii) Cumulative number of external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, by type of unit.

(iii) Report annual CO_2, CH_4, and N_2O emissions from external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, expressed in metric tons CO_2e for each gas, by type of unit.

(iv) Cumulative volume of fuel combusted in external fuel combustion units with a rated heat capacity larger than 5 mmBtu/hr, by fuel type.

(v) Cumulative number of internal fuel combustion units, not compressor-drivers, with a rated heat capacity equal to or less than 1 mmBtu/hr or 130 horsepower, by type of unit.

(vi) Report annual CO_2, CH_4, and N_2O emissions from internal combustion units greater than 1mmBtu/hr, expressed in metric tons CO_2e for each gas, by type of unit.

(vii) Cumulative volume of fuel combusted in internal combustion units with a rated heat capacity larger than 1 mmBtu/hr or 130 horsepower, by fuel type.

(d) Report annual throughput as determined by engineering estimate based on best available data for each industry segment listed in paragraphs (a)(1) through (a)(8) of this section.

(e) For onshore petroleum and natural gas production, report the best available estimate of API gravity, best available estimate of gas to oil ratio, and best available estimate of average low pressure separator pressure for each oil sub-basin category.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80587, Dec. 23, 2011; 77 FR 51494, Aug. 24, 2012]

§ 98.237 Records that must be retained.

Monitoring Plans, as described in §98.3(g)(5), must be completed by April 1, 2011. In addition to the information required by §98.3(g), you must retain the following records:

(a) Dates on which measurements were conducted.

(b) Results of all emissions detected and measurements.

(c) Calibration reports for detection and measurement instruments used.

(d) Inputs and outputs of calculations or emissions computer model runs used for engineering estimation of emissions.

(e) The records required under §98.3(g)(2)(i) shall include an explanation of how company records, engineering estimation, or best available information are used to calculate each applicable parameter under this subpart.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80590, Dec. 23, 2011]

§ 98.238 Definitions.

Except as provided in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

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

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

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

Associated with a single well-pad means associated with the hydrocarbon stream as produced from one or more wells located on that single well-pad. The association ends where the stream from a single well-pad is combined with streams from one or more additional single well-pads, where the point of combination is located off that single well-pad. Onshore production storage tanks on or associated with a single well-pad are considered a part of the onshore production facility.

Basin means geologic provinces as defined by the American Association of Petroleum Geologists (AAPG) Geologic Note: AAPG–CSD Geologic Provinces Code Map: AAPG Bulletin, Prepared by Richard F. Meyer, Laure G. Wallace, and Fred J. Wagner, Jr., Volume 75, Number 10 (October 1991) (incorporated by reference, see §98.7) and the Alaska Geological Province Boundary Map, Compiled by the American Association of Petroleum Geologists Committee on Statistics of Drilling in Cooperation with the USGS, 1978 (incorporated by reference, see § 98.7).

Component means each metal to metal joint or seal of non-welded connection separated by a compression gasket, screwed thread (with or without thread sealing compound), metal to metal compression, or fluid barrier through which natural gas or liquid can escape to the atmosphere.

Compressor means any machine for raising the pressure of a natural gas or CO_2 by drawing in low pressure natural gas or CO_2 and discharging significantly higher pressure natural gas or CO_2.

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

Distribution pipeline means a pipeline that is designated as such by the Pipeline and Hazardous Material Safety Administration (PHMSA) 49 CFR 192.3.

Engineering estimation, for purposes of subpart W, means an estimate of emissions based on engineering principles applied to measured and/or approximated physical parameters such as dimensions of containment, actual pressures, actual temperatures, and compositions.

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

Equipment leak means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Equipment leak detection means the process of identifying emissions from equipment, components, and other point sources.

External combustion means fired combustion in which the flame and products of combustion are separated from contact with the process fluid to which the energy is delivered. Process fluids may be air, hot water, or hydrocarbons. External combustion equipment may include fired heaters, industrial boilers, and commercial and domestic combustion units.

Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to natural gas distribution for purposes of reporting under this subpart and for the corresponding subpart A requirements means the collection of all distribution pipelines and metering-regulating stations that are operated by a Local Distribution Company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that are operated as an independent municipally-owned distribution system.

Facility with respect to onshore petroleum and natural gas production for purposes of reporting under this subpart and for the corresponding subpart A requirements means all petroleum or natural gas equipment on a single well-pad or associated with a single well-pad and CO_2 EOR operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and natural gas production owner or operator and that are located in a single hydrocarbon basin as defined in § 98.238. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and natural gas production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

Farm Taps are pressure regulation stations that deliver gas directly from transmission pipelines to generally rural customers. In some cases a nearby LDC may handle the billing of the gas to the customer(s).

Field means oil and gas fields identified in the United States as defined by the Energy Information Administration Oil and Gas Field Code Master List 2008, DOE/EIA 0370(08) (incorporated by reference, see § 98.7).

Flare, for the purposes of subpart W, means a combustion device, whether at ground level or elevated, that uses an open or closed flame to combust waste gases without energy recovery.

Flare combustion efficiency means the fraction of hydrocarbon gas, on a volume or mole basis, that is combusted at the flare burner tip.

Flare stack emissions means CO_2 and N_2O from partial combustion of hydrocarbon gas sent to a flare plus CH_4 emissions resulting from the incomplete combustion of hydrocarbon gas in flares.

Forced extraction of natural gas liquids means removal of ethane or higher carbon number hydrocarbons existing in the vapor phase in natural gas, by removing ethane or heavier hydrocarbons derived from natural gas into natural gas liquids by means of a forced extraction process. Forced extraction processes include but are not limited to refrigeration, absorption (lean oil), cryogenic expander, and combinations of these processes. Forced extraction does not include in and of itself; natural gas dehydration, or the collection or gravity separation of water or hydrocarbon liquids from natural gas at ambient temperature or heated above ambient temperatures, or the condensation of water or hydrocarbon liquids through passive reduction in pressure or temperature, or portable dewpoint suppression skids.

Horizontal well means a well bore that has a planned deviation from primarily vertical to a primarily horizontal inclination or declination tracking in parallel with and through the target formation.

Internal combustion means the combustion of a fuel that occurs with an oxidizer (usually air) in a combustion chamber. In an internal combustion engine the expansion of the high-temperature and –pressure gases produced by combustion applies direct force to a component of the engine, such as pistons, turbine blades, or a nozzle. This force moves the component over a distance, generating useful mechanical energy. Internal combustion equipment may include gasoline and diesel industrial engines, natural gas-fired reciprocating engines, and gas turbines.

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

LNG boil-off gas means natural gas in the gaseous phase that vents from LNG storage tanks due to ambient heat leakage through the tank insulation and heat energy dissipated in the LNG by internal pumps.

Meter/regulator run means a series of components used in regulating pressure or metering natural gas flow or both.

Metering-regulating station means a station that meters the flowrate, regulates the pressure, or both, of natural gas in a natural gas distribution facility. This does not include customer meters, customer regulators, or farm taps.

Natural gas means a naturally occurring mixture or process derivative of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the earth's surface, of which its constituents include, but are not limited to, methane, heavier hydrocarbons and carbon dioxide. Natural gas may be field quality, pipeline quality, or process gas.

Offshore means seaward of the terrestrial borders of the United States, including waters subject to the ebb and flow of the tide, as well as adjacent bays, lakes or other normally standing waters, and extending to the outer boundaries of the jurisdiction and control of the United States under the Outer Continental Shelf Lands Act.

Onshore petroleum and natural gas production owner or operator means the person or entity who holds the permit to operate petroleum and natural gas wells on the drilling permit or an operating permit where no drilling permit is issued, which operates an onshore petroleum and/or natural gas production facility (as described in § 98.230(a)(2). Where petroleum and natural gas wells operate without a drilling or operating permit, the person or entity that pays the State or Federal business income taxes is considered the owner or operator.

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

Pressure groups as applicable to each sub-basin are defined as follows: Less than or equal to 25 psig; greater than 25 psig and less than or equal to 60 psig; greater than 60 psig and less than or equal to 110 psig; greater than 110 psig and less than or equal to 200 psig; and greater than 200 psig. The pressure in the context of pressure groups is either the well shut-in pressure; well casing pressure; or you may use the casing-to-tubing pressure of one well from the same sub-basin multiplied by the tubing pressure for each well in the sub-basin.

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

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

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

Reservoir means a porous and permeable underground natural formation containing significant quantities of hydrocarbon liquids and/or gases.

Residue Gas and *Residue Gas Compression* mean, respectively, production lease natural gas from which gas liquid products and, in some cases, non-hydrocarbon components have been extracted such that it meets the specifications set by a pipeline transmission company, and/or a distribution company; and the compressors operated by the processing facility, whether inside the processing facility boundary fence or outside the fence-line, that deliver the residue gas from the processing facility to a transmission pipeline.

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

Sub-basin category, for onshore natural gas production, means a subdivision of a basin into the unique combination of wells with the surface coordinates within the boundaries of an individual county and subsurface completion in one or more of each of the following five formation types: Oil, high permeability gas, shale gas, coal seam, or other tight reservoir rock. The distinction between high permeability gas and tight gas reservoirs shall be designated as follows: High permeability gas reservoirs with >0.1 millidarcy permeability, and tight gas reservoirs with ≤0.1 millidarcy permeability. Permeability for a reservoir type shall be determined by engineering estimate. Wells that produce from high permeability gas, shale gas, coal seam, or other tight reservoir rock are considered gas wells; gas wells producing from more than one of these formation types shall be classified into only one type based on the formation with the most contribution to production as determined by engineering knowledge. All wells that produce hydrocarbon liquids and do not meet the definition of a gas well in this sub-basin category definition are considered to be in the oil formation. All emission sources that handle condensate from gas wells in high permeability gas, shale gas, or tight reservoir rock formations are considered to be in the formation that the gas well belongs to and not in the oil formation.

Transmission-distribution (T–D) transfer station means a metering-regulating station where a local distribution company takes part or all of the natural gas from a transmission pipeline and puts it into a distribution pipeline.

Transmission pipeline means a Federal Energy Regulatory Commission rate-regulated Interstate pipeline, a state rate-regulated Intrastate pipeline, or a pipeline that falls under the ‘‘Hinshaw Exemption’’ as referenced in section 1(c) of the Natural Gas Act, 15 U.S.C. 717–717 (w)(1994).

Tubing diameter groups are defined as follows: Outer diameter less than or equal to 1 inch; outer diameter greater than 1 inch and less than 2.375 inch; and outer diameter greater than or equal to 2.375 inch.

Tubing systems means piping equal to or less than one half inch diameter as per nominal pipe size.

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

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

Vertical well means a well bore that is primarily vertical but has some unintentional deviation or one or more intentional deviations to enter one or more subsurface targets that are offset horizontally from the surface location, intercepting the targets either vertically or at an angle.

Well testing venting and flaring means venting and/or flaring of natural gas at the time the production rate of a well is determined for regulatory, commercial, or technical purposes. If well testing is conducted immediately after well completion or workover, then it is considered part of well completion or workover.

[75 FR 74488, Nov. 30, 2010, as amended at 76 FR 80590, Dec. 23, 2011]

Table W–1A of Subpart W of Part 98—Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production

Onshore petroleum and natural gas production	Emission factor (scf/hour/component)
Eastern U.S.	
Population Emission Factors—All Components, Gas Service [1]	
Valve	0.027
Connector	0.003
Open-ended Line	0.061
Pressure Relief Valve	0.040
Low Continuous Bleed Pneumatic Device Vents [2]	1.39
High Continuous Bleed Pneumatic Device Vents [2]	37.3
Intermittent Bleed Pneumatic Device Vents [2]	13.5
Pneumatic Pumps [3]	13.3
Population Emission Factors—All Components, Light Crude Service [4]	
Valve	0.05
Flange	0.003
Connector	0.007
Open-ended Line	0.05
Pump	0.01
Other [5]	0.30
Population Emission Factors—All Components, Heavy Crude Service [6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other [5]	0.003
Western U.S.	
Population Emission Factors—All Components, Gas Service [1]	
Valve	0.121
Connector	0.017
Open-ended Line	0.031
Pressure Relief Valve	0.193
Low Continuous Bleed Pneumatic Device Vents [2]	1.39
High Continuous Bleed Pneumatic Device Vents [2]	37.3
Intermittent Bleed Pneumatic Device Vents [2]	13.5
Pneumatic Pumps [3]	13.3
Population Emission Factors—All Components, Light Crude Service [4]	
Valve	0.05
Flange	0.003
Connector (other)	0.007
Open-ended Line	0.05
Pump	0.01
Other [5]	0.30
Population Emission Factors—All Components, Heavy Crude Service [6]	
Valve	0.0005
Flange	0.0009
Connector (other)	0.0003
Open-ended Line	0.006
Other [5]	0.003

[1] For multi-phase flow that includes gas, use the gas service emissions factors.

[2] Emission Factor is in units of "scf/hour/device."

[3] Emission Factor is in units of "scf/hour/pump."

[4] Hydrocarbon liquids greater than or equal to 20°API are considered "light crude."

[5] "Others" category includes instruments, loading arms, pressure relief valves, stuffing boxes, compressor seals, dump lever arms, and vents.

[6] Hydrocarbon liquids less than 20°API are considered "heavy crude."

[77 FR 51494, Aug. 24, 2012]

TABLE W–1B TO SUBPART W OF PART 98—DEFAULT AVERAGE COMPONENT COUNTS FOR MAJOR ONSHORE NATURAL GAS PRODUCTION EQUIPMENT

Major equipment	Valves	Connectors	Open-ended lines	Pressure relief valves
Eastern U.S.				
Wellheads	8	38	0.5	0
Separators	1	6	0	0
Meters/piping	12	45	0	0
Compressors	12	57	0	0
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2
Western U.S.				
Wellheads	11	36	1	0
Separators	34	106	6	2
Meters/piping	14	51	1	1
Compressors	73	179	3	4
In-line heaters	14	65	2	1
Dehydrators	24	90	2	2

TABLE W–1C TO SUBPART W OF PART 98—DEFAULT AVERAGE COMPONENT COUNTS FOR MAJOR CRUDE OIL PRODUCTION EQUIPMENT

Major equipment	Valves	Flanges	Connectors	Open-ended lines	Other components
Eastern U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0
Western U.S.					
Wellhead	5	10	4	0	1
Separator	6	12	10	0	0
Heater-treater	8	12	20	0	0
Header	5	10	4	0	0

TABLE W–1D OF SUBPART W OF PART 98—DESIGNATION OF EASTERN AND WESTERN U.S.

Eastern U.S.	Western U.S.
Connecticut	Alabama
Delaware	Alaska
Florida	Arizona
Georgia	Arkansas
Illinois	California
Indiana	Colorado
Kentucky	Hawaii
Maine	Idaho
Maryland	Iowa
Massachusetts	Kansas
Michigan	Louisiana
New Hampshire	Minnesota
New Jersey	Mississippi
New York	Missouri
North Carolina	Montana
Ohio	Nebraska
Pennsylvania	Nevada
Rhode Island	New Mexico
South Carolina	North Dakota
Tennessee	Oklahoma
Vermont	Oregon
Virginia	South Dakota
West Virginia	Texas
Wisconsin	Utah
	Washington
	Wyoming

TABLE W–2 OF SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR ONSHORE NATURAL GAS PROCESSING

Onshore natural gas processing plants	Emission factor (scf/hour/ component)
Leaker Emission Factors—Compressor Components, Gas Service	
Valve [1]	14.84
Connector	5.59
Open-Ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33
Leaker Emission Factors—Non-Compressor Components, Gas Service	
Valve [1]	6.42
Connector	5.71
Open-Ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93

[1] Valves include control valves, block valves and regulator valves.

[76 FR 80592, Dec. 23, 2011]

TABLE W–3 OF SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR ONSHORE NATURAL GAS TRANSMISSION COMPRESSION

Onshore natural gas transmission compression	Emission factor (scf/hour/ component)
Leaker Emission Factors—Compressor Components, Gas Service	
Valve [1]	14.84
Connector	5.59
Open-Ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33
Leaker Emission Factors—Non-Compressor Components, Gas Service	
Valve [1]	6.42
Connector	5.71
Open-Ended Line	11.27
Pressure Relief Valve	2.01
Meter	2.93
Population Emission Factors—Gas Service	
Low Continuous Bleed Pneumatic Device Vents [2]	1.37
High Continuous Bleed Pneumatic Device Vents [2]	18.20
Intermittent Bleed Pneumatic Device Vents [2]	2.35

[1] Valves include control valves, block valves and regulator valves.
[2] Emission Factor is in units of "scf/hour/device."

[76 FR 80593, Dec. 23, 2011]

TABLE W–4 OF SUBPART W OF PART 98—DEFAULT TOTAL HYDROCARBON EMISSION FACTORS FOR UNDERGROUND NATURAL GAS STORAGE

Underground natural gas storage	Emission factor (scf/hour/ component)
Leaker Emission Factors—Storage Station, Gas Service	
Valve [1]	14.84
Connector	5.59
Open-Ended Line	17.27
Pressure Relief Valve	39.66
Meter	19.33

Underground natural gas storage	Emission factor (scf/hour/ component)
Population Emission Factors—Storage Wellheads, Gas Service	
Connector	0.01
Valve	0.1
Pressure Relief Valve	0.17
Open Ended Line	0.03
Population Emission Factors—Other Components, Gas Service	
Low Continuous Bleed Pneumatic Device Vents [2]	1.37
High Continuous Bleed Pneumatic Device Vents [2]	18.20
Intermittent Bleed Pneumatic Device Vents [2]	2.35

[1] Valves include control valves, block valves and regulator valves.
[2] Emission Factor is in units of "scf/hour/device."

[76 FR 80593, Dec. 23, 2011]

TABLE W–5 OF SUBPART W OF PART 98—DEFAULT METHANE EMISSION FACTORS FOR LIQUEFIED NATURAL GAS (LNG) STORAGE

LNG storage	Emission factor (scf/hour/ component)
Leaker Emission Factors—LNG Storage Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other [1]	1.77
Population Emission Factors—LNG Storage Compressor, Gas Service	
Vapor Recovery Compressor [2]	4.17

[1] "Other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.
[2] Emission Factor is in units of "scf/hour/device."

[76 FR80594, Dec. 23, 2011, as amended at 77 FR 51495, Aug. 24, 2012]

TABLE W–6 OF SUBPART W OF PART 98—DEFAULT METHANE EMISSION FACTORS FOR LNG IMPORT AND EXPORT EQUIPMENT

LNG import and export equipment	Emission factor (scf/hour/ component)
Leaker Emission Factors—LNG Terminals Components, LNG Service	
Valve	1.19
Pump Seal	4.00
Connector	0.34
Other [1]	1.77
Population Emission Factors—LNG Terminals Compressor, Gas Service	
Vapor Recovery Compressor [2]	4.17

[1] "Other" equipment type should be applied for any equipment type other than connectors, pumps, or valves.
[2] Emission Factors is in units of "scf/hour/compressor."

[76 FR 80594, Dec. 23, 2011]

TABLE W–7 OF SUBPART W OF PART 98—DEFAULT METHANE EMISSION FACTORS FOR NATURAL GAS DISTRIBUTION

Natural gas distribution	Emission factor (scf/hour/ component)
Leaker Emission Factors—Transmission-Distribution Transfer Station [1] Components, Gas Service	

Natural gas distribution	Emission factor (scf/hour/ component)
Connector	1.69
Block Valve	0.557
Control Valve	9.34
Pressure Relief Valve	0.27
Orifice Meter	0.212
Regulator	0.772
Open-ended Line	26.131
Population Emission Factors—Below Grade Metering-Regulating station [1] Components, Gas Service [2]	
Below Grade M&R Station, Inlet Pressure >300 psig	1.30
Below Grade M&R Station, Inlet Pressure 100 to 300 psig	0.20
Below Grade M&R Station, Inlet Pressure <100 psig	0.10
Population Emission Factors—Distribution Mains, Gas Service [3]	
Unprotected Steel	12.58
Protected Steel	0.35
Plastic	1.13
Cast Iron	27.25
Population Emission Factors—Distribution Services, Gas Service [4]	
Unprotected Steel	0.19
Protected Steel	0.02
Plastic	0.001
Copper	0.03

[1] Excluding customer meters.
[2] Emission Factor is in units of "scf/hour/station."
[3] Emission Factor is in units of "scf/hour/mile."
[4] Emission Factor is in units of "scf/hour/number of services."

[76 FR 80594, Dec. 23, 2011]

Subpart X—Petrochemical Production

§ 98.240 Definition of the source category.

(a) The petrochemical production source category consists of all processes that produce acrylonitrile, carbon black, ethylene, ethylene dichloride, ethylene oxide, or methanol, except as specified in paragraphs (b) through (g) of this section. The source category includes processes that produce the petrochemical as an intermediate in the on-site production of other chemicals as well as processes that produce the petrochemical as an end product for sale or shipment off site.

(b) A process that produces a petrochemical as a byproduct is not part of the petrochemical production source category.

(c) A facility that makes methanol, hydrogen, and/or ammonia from synthesis gas is part of the petrochemical source category if the annual mass of methanol produced exceeds the individual annual mass production levels of both hydrogen recovered as product and ammonia. The facility is part of subpart P of this part (Hydrogen Production) if the annual mass of hydrogen recovered as product exceeds the individual annual mass production levels of both methanol and ammonia. The facility is part of subpart G of this part (Ammonia Manufacturing) if the annual mass of ammonia produced exceeds the individual annual mass production levels of both hydrogen recovered as product and methanol.

(d) A direct chlorination process that is operated independently of an oxychlorination process to produce ethylene dichloride is not part of the petrochemical production source category.

(e) A process that produces bone black is not part of the petrochemical source category.

(f) A process that produces a petrochemical from bio-based feedstock is not part of the petrochemical production source category.

(g) A process that solely distills or recycles waste solvent that contains a petrochemical is not part of the petrochemical production source category.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79157, Dec. 17, 2010; 76 FR 80590, Dec. 23, 2011]

§98.241 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a petrochemical process as specified in §98.240, and the facility meets the requirements of either §98.2(a)(1) or (2).

§98.242 GHGs to report.

You must report the information in paragraphs (a) through (c) of this section:

(a) CO_2 CH_4, and N_2O process emissions from each petrochemical process unit. Process emissions include CO_2 generated by reaction in the process and by combustion of process off-gas in stationary combustion units and flares.

(1) If you comply with §98.243(b) or (d), report under this subpart the calculated CO_2, CH_4, and N_2O emissions for each stationary combustion source and flare that burns any amount of petrochemical process off-gas. If you comply with §98.243(b), also report under this subpart the measured CO_2 emissions from process vents routed to stacks that are not associated with stationary combustion units.

(2) If you comply with §98.243(c), report under this subpart the calculated CO_2 emissions for each petrochemical process unit.

(b) CO_2, CH_4, and N_2O combustion emissions from stationary combustion units.

(1) If you comply with §98.243(b) or (d), report these emissions from stationary combustion units that are associated with petrochemical process units and burn only supplemental fuel under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(2) If you comply with §98.243(c), report CO_2, CH_4, and N_2O combustion emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C for all fuels, except emissions from burning petrochemical process off-gas in any combustion unit, including units that are not part of the petrochemical process unit, are not to be reported under subpart C of this part. Determine the applicable Tier in subpart C of this part (General Stationary Fuel Combustion Sources) based on the maximum rated heat input capacity of the stationary combustion source.

(c) CO_2 captured. You must report the mass of CO_2 captured under, subpart PP of this part (Suppliers of Carbon Dioxide (CO_2) by following the requirements of subpart PP.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79157, Dec. 17, 2010; 78 FR 71960, Nov. 29, 2013]

§98.243 Calculating GHG emissions.

(a) If you route all process vent emissions and emissions from combustion of process off-gas to one or more stacks and use CEMS on each stack to measure CO_2 emissions (except flare stacks), then you must determine process-based GHG emissions in accordance with paragraph (b) of this section. Otherwise, determine process-based GHG emissions in accordance with the procedures specified in paragraph (c) or (d) of this section.

(b) *Continuous emission monitoring system (CEMS).* Route all process vent emissions and emissions from stationary combustion units that burn any amount of process off-gas to one or more stacks and determine GHG emissions as specified in paragraphs (b)(1) through (3) of this section.

(1) Determine CO_2 emissions from each stack (except flare stacks) according to the Tier 4 Calculation Methodology requirements in subpart C of this part.

(2) For each stack (except flare stacks) that includes emissions from combustion of petrochemical process off-gas, calculate CH_4 and N_2O emissions in accordance with subpart C of this part (use Equation C–10 and the ''fuel gas'' emission factors in Table C–2 of subpart C of this part).

(3) For each flare, calculate CO_2, CH_4, and N_2O emissions using the methodology specified in §98.253(b)(1) through (3).

(c) *Mass balance for each petrochemical process unit.* Calculate the emissions of CO_2 from each process unit, for each calendar month as described in paragraphs (c)(1) through (c)(5) of this section.

(1) For each gaseous and liquid feedstock and product, measure the volume or mass used or produced each calendar month with a flow meter by following the procedures specified in § 98.244(b)(2). Alternatively, for liquids, you may calculate the volume used or collected in each month based on measurements of the liquid level in a storage tank at least once per month (and just prior to each change in direction of the level of the liquid) following the procedures specified in § 98.244(b)(3). Fuels used for combustion purposes are not considered to be feedstocks.

(2) For each solid feedstock and product, measure the mass used or produced each calendar month by following the procedures specified in § 98.244(b)(1).

(3) Collect a sample of each feedstock and product at least once per month and determine the carbon content of each sample according to the procedures of § 98.244(b)(4). If multiple valid carbon content measurements are made during the monthly measurement period, average them arithmetically. However, if a particular liquid or solid feedstock is delivered in lots, and if multiple deliveries of the same feedstock are received from the same supply source in a given calendar month, only one representative sample is required. Alternatively, you may use the results of analyses conducted by a feedstock supplier, or product customer, provided the sampling and analysis is conducted at least once per month using any of the procedures specified in § 98.244(b)(4).

(4) If you determine that the monthly average concentration of a specific compound in a feedstock or product is greater than 99.5 percent by volume or mass, then as an alternative to the sampling and analysis specified in paragraph (c)(3) of this section, you may determine carbon content in accordance with paragraphs (c)(4)(i) through (iii) of this section.

(i) Calculate the carbon content assuming 100 percent of that feedstock or product is the specific compound.

(ii) Maintain records of any determination made in accordance with this paragraph (c)(4) along with all supporting data, calculations, and other information.

(iii) Reevaluate determinations made under this paragraph (c)(4) after any process change that affects the feedstock or product composition. Keep records of the process change and the corresponding composition determinations. If the feedstock or product composition changes so that the average monthly concentration falls below 99.5 percent, you are no longer permitted to use this alternative method.

(5) Calculate the CO_2 mass emissions for each petrochemical process unit using Equations X–1 through X–4 of this section.

(i) *Gaseous feedstocks and products.* Use Equation X–1 of this section to calculate the net annual carbon input or output from gaseous feedstocks and products. Note that the result will be a negative value if there are no gaseous feedstocks in the process but there are gaseous products.

$$C_g = \sum_{n=1}^{12}\left[\sum_{i=1}^{j\,or\,k}\left[\left(F_{gf}\right)_{i,n} * \left(CC_{gf}\right)_{i.n} * \frac{\left(MW_f\right)_{i,n}}{MVC} - \left(P_{gp}\right)_{i,n} * \left(CC_{gp}\right)_{i,n} * \frac{\left(MW_p\right)_{i,n}}{MVC}\right]\right] \quad \text{(Eq. X-1)}$$

Where:

C_g = Annual net contribution to calculated emissions from carbon (C) in gaseous materials, including streams containing CO_2 recovered for sale or use in another process (kg/yr).

$(F_{gf})_{i,n}$ = Volume or mass of gaseous feedstock i introduced in month ‘‘n’’ (scf or kg). If you measure mass, the term $(MW_f)_{i,n}/MVC$ is replaced with ‘‘1’’.

$(CC_{gf})_{i,n}$ = Average carbon content of the gaseous feedstock i for month ‘‘n’’ (kg C per kg of feedstock).

$(MW_f)_{i,n}$ = Molecular weight of gaseous feedstock i in month "n"(kg/kg-mole).

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

$(P_{gp})_{i,n}$ = Volume or mass of gaseous product i produced in month "n" (scf or kg). If you measure mass, the term $(MW_p)_{i,n}$/MVC is replaced with "1".

$(CC_{gp})_{i,n}$ = Average carbon content of gaseous product i, including streams containing CO_2 recovered for sale or use in another process, for month "n" (kg C per kg of product).

$(MW_p)_{i,n}$ = Molecular weight of gaseous product i in month "n" (kg/kg-mole).

j = Number of feedstocks.

k = Number of products.

(ii) *Liquid feedstocks and products.* Use Equation X–2 of this section to calculate the net carbon input or output from liquid feedstocks and products. Note that the result will be a negative value if there are no liquid feedstocks in the process but there are liquid products.

$$C_l = \sum_{n=1}^{12}\left[\sum_{i=1}^{j\ or\ k}\left[\left(F_{lf}\right)_{i,n} * \left(CC_{lf}\right)_{i,n} - \left(P_{lp}\right)_{i,n} * \left(CC_{lp}\right)_{i,n}\right]\right] \qquad \text{(Eq. X-2)}$$

Where:

C_l = Annual net contribution to calculated emissions from carbon in liquid materials, including liquid organic wastes (kg/yr).

$(F_{lf})_{i,n}$ = Volume or mass of liquid feedstock i introduced in month "n" (gallons or kg).

$(CC_{lf})_{i,n}$ = Average carbon content of liquid feedstock i for month "n" (kg C per gallon or kg of feedstock).

$(P_{lp})_{i,n}$ = Volume or mass of liquid product i produced in month "n" (gallons or kg).

$(CC_{lp})_{i,n}$ = Average carbon content of liquid product i, including organic liquid wastes, for month "n" (kg C per gallon or kg of product).

j = Number of feedstocks.

k = Number of products.

(iii) *Solid feedstocks and products.* Use Equation X–3 of this section to calculate the net annual carbon input or output from solid feedstocks and products. Note that the result will be a negative value if there are no solid feedstocks in the process but there are solid products.

$$C_s = \sum_{n=1}^{12}\left\{\sum_{i=1}^{j\ or\ k}\left[\left(F_{sf}\right)_{i,n} * \left(CC_{sf}\right)_{i,n} - \left(P_{sp}\right)_{i,n} * \left(CC_{sp}\right)_{i,n}\right]\right\} \qquad \text{(Eq. X-3)}$$

Where:

C_s = Annual net contribution to calculated emissions from carbon in solid materials (kg/yr).

$(F_{sf})_{i,n}$ = Mass of solid feedstock i introduced in month "n" (kg).

$(CC_{sf})_{i,n}$ = Average carbon content of solid feedstock i for month "n" (kg C per kg of feedstock).

$(P_{sp})_{i,n}$ = Mass of solid product i produced in month "n" (kg).

$(CC_{sp})_{i,n}$ = Average carbon content of solid product i in month "n" (kg C per kg of product).

j = Number of feedstocks.

k = Number of products.

(iv) *Annual emissions.* Use the results from Equations X–1 through X–3 of this section, as applicable, in Equation X–4 of this section to calculate annual CO_2 emissions.

$$CO_2 = 0.001 * \frac{44}{12} * \left(C_g + C_l + C_s\right) \qquad \text{(Eq. X-4)}$$

Where:

CO_2 = Annual CO_2 mass emissions from process operations and process off-gas combustion (metric tons/year).

0.001 = Conversion factor from kg to metric tons.

44 = Molecular weight of CO_2 (kg/kg-mole).

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

(d) *Optional combustion methodology for ethylene production processes.* For each ethylene production process, calculate GHG emissions from combustion units that burn fuel that contains any off-gas from the ethylene process as specified in paragraphs (d)(1) through (d)(5) of this section.

(1) Except as specified in paragraphs (d)(2) and (d)(5) of this section, calculate CO_2 emissions using the Tier 3 or Tier 4 methodology in subpart C of this part.

(2) You may use either Equation C–1 or Equation C–2a in subpart C of this part to calculate CO_2 emissions from combustion of any ethylene process off-gas streams that meet either of the conditions in paragraphs (d)(2)(i) or (d)(2)(ii) of this section (for any default values in the calculation, use the defaults for fuel gas in Table C–1 of subpart C of this part). Follow the otherwise applicable procedures in subpart C to calculate emissions from combustion of all other fuels in the combustion unit.

(i) The annual average flow rate of fuel gas (that contains ethylene process off-gas) 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 a flow meter is not installed at any point in the line supplying fuel gas or an upstream common pipe. Calculate the annual average flow rate using company records assuming total flow is evenly distributed over 525,600 minutes per year.

(ii) The combustion unit has a maximum rated heat input capacity of less than 30 mmBtu/hr, and a flow meter is not installed at any point in the line supplying fuel gas (that contains ethylene process off-gas) or an upstream common pipe.

(3) Except as specified in paragraph (d)(5) of this section, calculate CH_4 and N_2O emissions using the applicable procedures in § 98.33(c) for the same tier methodology that you used for calculating CO_2 emissions.

(i) For all gaseous fuels that contain ethylene process off-gas, use the emission factors for ‘‘Fuel Gas’’ in Table C–2 of subpart C of this part (General Stationary Fuel Combustion Sources).

(ii) 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.

(4) You are not required to use the same Tier for each stationary combustion unit that burns ethylene process off-gas.

(5) For each flare, calculate CO_2, CH_4, and N_2O emissions using the methodology specified in §§ 98.253(b)(1) through (b)(3).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79157, Dec. 17, 2010; 78 FR 71961, Nov. 29, 2013]

§ 98.244 Monitoring and QA/QC requirements.

(a) If you use CEMS to determine emissions from process vents, you must comply with the procedures specified in § 98.34(c).

(b) If you use the mass balance methodology in § 98.243(c), use the procedures specified in paragraphs (b)(1) through (b)(4) of this section to determine feedstock and product flows and carbon contents.

(1) Operate, maintain, and calibrate belt scales or other weighing devices as described in Specifications, Tolerances, and Other Technical Requirements for Weighing and Measuring Devices NIST Handbook 44 (2009) (incorporated by reference, see § 98.7), or follow procedures specified by the measurement device manufacturer. You must recalibrate each weighing device according to one of the following frequencies. You may recalibrate either at the minimum frequency specified by the manufacturer or biennially (*i.e.*, once every two years).

(2) Operate and maintain all flow meters used for gas and liquid feedstocks and products according to the manufacturer's recommended procedures. You must calibrate each of these flow meters as specified in paragraphs (b)(2)(i) and (b)(2)(ii) of this section:

(i) You may use either the calibration methods specified by the flow meter manufacturer or an industry consensus standard method. Each flow meter must meet the applicable accuracy specification in § 98.3(i), except as otherwise specified in §§ 98.3(i)(4) through (i)(6).

(ii) You must recalibrate each 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.

(3) You must perform tank level measurements (if used to determine feedstock or product flows) according to one of the following methods. You may use any standard method published by a consensus-based standards organization or you may use an industry standard practice. 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*).

(4) Beginning January 1, 2010, use any applicable methods specified in paragraphs (b)(4)(i) through (xv) of this section to determine the carbon content or composition of feedstocks and products and the average molecular weight of gaseous feedstocks and products. Calibrate instruments in accordance with paragraphs (b)(4)(i) through (xv) of this section, as applicable. For coal used as a feedstock, the samples for carbon content determinations shall be taken at a location that is representative of the coal feedstock used during the corresponding monthly period. For carbon black products, samples shall be taken of each grade or type of product produced during the monthly period. Samples of coal feedstock or carbon black product for carbon content determinations may be either grab samples collected and analyzed monthly or a composite of samples collected more frequently and analyzed monthly. Analyses conducted in accordance with methods specified in paragraphs (b)(4)(i) through (xv) of this section may be performed by the owner or operator, by an independent laboratory, by the supplier of a feedstock, or by a product customer.

(i) ASTM D1945–03, Standard Test Method for Analysis of Natural Gas by Gas Chromatography (incorporated by reference, *see* § 98.7).

(ii) ASTM D6060–96 (Reapproved 2001) Standard Practice for Sampling of Process Vents With a Portable Gas Chromatograph (incorporated by reference, *see* § 98.7).

(iii) ASTM D2505–88(Reapproved 2004)e1 Standard Test Method for Ethylene, Other Hydrocarbons, and Carbon Dioxide in High-Purity Ethylene by Gas Chromatography (incorporated by reference, *see* § 98.7).

(iv) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, *see* § 98.7).

(v) ASTM D3176–89 (Reapproved 2002) Standard Practice Method for Ultimate Analysis of Coal and Coke (incorporated by reference, *see* § 98.7).

(vi) 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).

(vii) 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).

(viii) Method 8015C, Method 8021B, Method 8031, or Method 9060A (all incorporated by reference, see § 98.7).

(x) Performance Specification 9 in 40 CFR part 60, appendix B for continuous online gas analyzers. The 7-day calibration error test period must be completed prior to the effective date of the rule.

(xi) ASTM D2593–93 (Reapproved 2009) Standard Test Method for Butadiene Purity and Hydrocarbon Impurities by Gas Chromatography (incorporated by reference, see § 98.7).

(xii) ASTM D7633–10 Standard Test Method for Carbon Black—Carbon Content (incorporated by reference, see § 98.7).

(xiii) The results of chromatographic analysis of a feedstock or product, provided that the chromatograph is operated, maintained, and calibrated according to the manufacturer's instructions.

(xiv) The results of mass spectrometer analysis of a feedstock or product, provided that the mass spectrometer is operated, maintained, and calibrated according to the manufacturer's instructions.

(xv) Beginning on January 1, 2010, the methods specified in paragraphs (b)(4)(xv)(A) and (B) of this section may be used as alternatives for the methods specified in paragraphs (b)(4)(i) through (b)(4)(xiv) of this section.

(A) An industry standard practice or a method published by a consensus-based standards organization if such a method exists for carbon black feedstock oils and carbon black products. 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.naesb.org*). The method(s) used shall be documented in the monitoring plan required under § 98.3(g)(5).

(B) Modifications of existing analytical methods or other methods that are applicable to your process provided that the methods listed in paragraphs (b)(4)(i) through (b)(4)(xiv) of this section are not appropriate because the relevant compounds cannot be detected, the quality control requirements are not technically feasible, or use of the method would be unsafe.

(c) If you comply with § 98.243(b) or (d), conduct monitoring and QA/QC for flares in accordance with § 98.254(b) through (e) for each flare gas flow meter, gas composition meter, and/or heating value monitor that you use to comply with § 98.253(b)(1) through (b)(3). You must implement all applicable QA/QC requirements specified in this paragraph (c) beginning no later than January 1, 2015.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79158, Dec. 17, 2010; 78 FR 71961, Nov. 29, 2013]

§ 98.245 Procedures for estimating missing data.

For missing feedstock and product flow rates, use the same procedures as for missing fuel usage as specified in § 98.35(b)(2). For missing feedstock and product carbon contents and missing molecular weights for gaseous feedstocks and products, use the same procedures as for missing carbon contents and missing molecular weights for fuels as specified in § 98.35(b)(1).

For missing flare data, follow the procedures in § 98.255(b) and (c).

[78 FR 71962, Nov. 29, 2013]

§ 98.246 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a), (b), or (c) of this section, as appropriate for each process unit.

(a) If you use the mass balance methodology in § 98.243(c), you must report the information specified in paragraphs (a)(1) through (a)(11) of this section for each type of petrochemical produced, reported by process unit.

(1) The petrochemical process unit ID number or other appropriate descriptor.

(2) The type of petrochemical produced, names of other products, and names of carbon-containing feedstocks.

(3) Annual CO_2 emissions calculated using Equation X–4 of this subpart.

(4) Each of the monthly volume, mass, and carbon content values used in Equations X–1 through X–3 of this subpart (*i.e.*, the directly measured values, substitute values, or the calculated values based on other measured data such as tank levels or gas composition) and the molecular weights for gaseous feedstocks and products used in Equation X–1 of this subpart, and the temperature (in °F) at which the gaseous feedstock and product volumes used in Equation X–1 of this subpart were determined. Indicate whether you used the alternative to sampling and analysis specified in § 98.243(c)(4).

(5) Annual quantity of each type of petrochemical produced from each process unit (metric tons).

(6) For each feedstock and product, provide the information specified in paragraphs (a)(6)(i) through (a)(6)(iii) of this section.

(i) Name of each method used to determine carbon content or molecular weight in accordance with § 98.244(b)(4);

(ii) Description of each type of device (e.g., flow meter, weighing device) used to determine flow or mass in accordance with § 98.244(b)(1) through (3).

(iii) Identification of each method (i.e., method number, title, or other description) used to determine flow or mass in accordance with § 98.244(b)(1) through (3).

(7) [Reserved]

(8) Identification of each combustion unit that burned both process off-gas and supplemental fuel, including combustion units that are not part of the petrochemical process unit.

(9) The number of days during which off-specification product was produced if the alternative to sampling and analysis specified in § 98.243(c)(4) is used for a product, and, if applicable, the date of any process change that reduced the monthly average composition to less than 99.5 percent for each product or feedstock for which you comply with the alternative to sampling and analysis specified in § 98.243(c)(4).

(10) You may elect to report the flow and carbon content of wastewater, and you may elect to report the annual mass of carbon released in fugitive emissions and in process vents that are not controlled with a combustion device. These values may be estimated based on engineering analyses. These values are not to be used in the mass balance calculation.

(11) If you determine carbon content or composition of a feedstock or product using a method under § 98.244(b)(4)(xv)(B), report the information listed in paragraphs (a)(11)(i) through (a)(11)(iii) of this section. Include the information in paragraph (a)(11)(i) of this section in each annual report. Include the information in paragraphs (a)(11)(ii) and (a)(11)(iii) of this section only in the first applicable annual report, and provide any changes to this information in subsequent annual reports.

(i) Name or title of the analytical method.

(ii) A copy of the method. If the method is a modification of a method listed in §§ 98.244(b)(4)(i) through (xiv), you may provide a copy of only the sections that differ from the listed method.

(iii) An explanation of why an alternative to the methods listed in §§ 98.244(b)(4)(i) through (xiv) is needed.

(b) If you measure emissions in accordance with § 98.243(b), then you must report the information listed in paragraphs (b)(1) through (b)(8) of this section.

(1) The petrochemical process unit ID or other appropriate descriptor, and the type of petrochemical produced.

(2) For CEMS used on stacks that include emissions from stationary combustion units that burn any amount of off-gas from the petrochemical process, report the relevant information required under § 98.36(c)(2) and (e)(2)(vi) for the Tier 4 calculation methodology. Sections 98.36(c)(2)(ii) and (c)(2)(ix) do not apply for the purposes of this subpart.

(3) For CEMS used on stacks that do not include emissions from stationary

combustion units, report the information required under § 98.36(b)(6), (b)(7), and (e)(2)(vi).

(4) For each CEMS monitoring location that meets the conditions in paragraph (b)(2) or (3) of this section, provide an estimate based on engineering judgment of the fraction of the total CO_2 emissions that results from CO_2 directly emitted by the petrochemical process unit plus CO_2 generated by the combustion of off-gas from the petrochemical process unit.

(5) For each CEMS monitoring location that meets the conditions in paragraph (b)(2) of this section, report the CH_4 and N_2O emissions expressed in metric tons of each gas. For each CEMS monitoring location, provide an estimate based on engineering judgment of the fraction of the total CH_4 and N_2O emissions that is attributable to combustion of off-gas from the petrochemical process unit.

(6) [Reserved]

(7) Information listed in § 98.256(e) of subpart Y of this part for each flare that burns process off-gas.

(8) Annual quantity of each type of petrochemical produced from each process unit (metric tons).

(c) If you comply with the combustion methodology specified in § 98.243(d), you must report under this subpart the information listed in paragraphs (c)(1) through (c)(5) of this section.

(1) The ethylene process unit ID or other appropriate descriptor.

(2) For each stationary combustion unit that burns ethylene process off-gas (or group of stationary sources with a common pipe), except flares, the relevant information listed in § 98.36 for the applicable Tier methodology. For each stationary combustion unit or group of units (as applicable) that burns ethylene process off-gas, provide an estimate based on engineering judgment of the fraction of the total emissions that is attributable to combustion of off-gas from the ethylene process unit.

(3) Information listed in § 98.256(e) of subpart Y of this part for each flare that burns ethylene process off-gas.

(4) Name and annual quantity of each feedstock (metric tons).

(5) Annual quantity of ethylene produced from each process unit (metric tons).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79159, Dec. 17, 2010; 78 FR 71962, Nov. 29, 2013]

§ 98.247 Records that must be retained.

In addition to the recordkeeping requirements in § 98.3(g), you must retain the records specified in paragraphs (a) through (c) of this section, as applicable.

(a) If you comply with the CEMS measurement methodology in § 98.243(b), then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37, records of the procedures used to develop estimates of the fraction of total emissions attributable to combustion of petrochemical process off-gas as required in § 98.246(b), and records of any annual average HHV calculations.

(b) If you comply with the mass balance methodology in § 98.243(c), then you must retain records of the information listed in paragraphs (b)(1) through (4) of this section.

(1) Results of feedstock or product composition determinations conducted in accordance with § 98.243(c)(4).

(2) Start and end times for time periods when off-specification product is produced, if you comply with the alternative methodology in § 98.243(c)(4) for determining carbon content of product.

(3) As part of the monitoring plan required under § 98.3(g)(5), record the estimated accuracy of measurement devices and the technical basis for these estimates.

(4) The dates and results (*e.g.*, percent calibration error) of the calibrations of each measurement device.

(c) If you comply with the combustion methodology in § 98.243(d), then you must retain under this subpart the records required for the applicable Tier Calculation Methodologies in § 98.37. If you comply with § 98.243(d)(2), you must also keep records of the annual average flow calculations.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79160, Dec. 17, 2010; 78 FR 71962, Nov. 29, 2013]

§98.248 Definitions.

Except as specified in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Product, as used in §98.243, means each of the following carbon-containing outputs from a process: the petrochemical, recovered byproducts, and liquid organic wastes that are not combusted onsite. Product does not include process vent emissions, fugitive emissions, or wastewater.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71963, Nov. 29, 2013]

Subpart Y—Petroleum Refineries

§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) CO_2, CH_4, and N_2O 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. For CO_2 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 CH_4 and N_2O emissions from combustion of fuel gas, use the applicable procedures in §98.33(c) for the same tier methodology that was used for calculating CO_2 emissions. (Use the default CH_4 and N_2O emission factors for ''Fuel Gas'' 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) CO_2, CH_4, and N_2O coke burn-off emissions from each catalytic cracking unit, fluid coking unit, and catalytic reforming unit under this subpart.

(c) CO_2 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) CO_2 process emissions from each on-site sulfur recovery plant under this subpart.

(e) CO_2, CH_4, and N_2O emissions from each coke calcining unit under this subpart.

(f) CO_2 and CH_4 emissions from asphalt blowing operations under this subpart.

(g) CH_4 emissions from equipment leaks, storage tanks, loading operations, delayed coking units, and uncontrolled blowdown systems under this subpart.

(h) CO_2, CH_4, and N_2O emissions from each process vent not specifically included in paragraphs (a) through (g) of this section under this subpart.

(i) CO_2 emissions from non-merchant hydrogen production process units (not including hydrogen produced from catalytic reforming units) following the calculation methodologies, monitoring and QA/QC methods, missing data procedures, reporting requirements, and recordkeeping requirements of subpart P of this part.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79160, Dec. 17, 2010; 78 FR 71963, Nov. 29, 2013]

§ 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 CO_2 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 CO_2 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 CO_2 emissions from the flare using either 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.

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

where:

CO_2 = Annual CO_2 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 CO_2 (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.

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

where:

CO_2 = Annual CO_2 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 CO_2 (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).

$(\%CO_2)_p$ = Mole percent CO_2 concentration in the flare gas stream during the measurement period (mole percent = percent by volume).

y = Number of carbon-containing compounds other than CO_2 in the flare gas stream.

x = Index for carbon-containing compounds other than CO_2.

0.98 = Assumed combustion efficiency of a flare (mole CO_2 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 (C_2H_6) is 2; CMN for propane (C_3H_8) is 3.

(B) If you monitor heat content but do not monitor gas composition, calculate the CO_2 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.

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

Where:

CO_2 = Annual CO_2 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 × Flare[kg] × 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 CO_2 emission factor of 60 kilograms CO_2/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 CO_2 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 CO_2 emissions using Equation Y–3 of this section.

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

Where:

CO_2 = Annual CO_2 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 CO_2 emission factor for flare gas of 60 kilograms CO_2/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 CO_2 (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 CH_4 using Equation Y–4 of this section.

$$CH_4 = \left(CO_2 \times \frac{EmF_{CH4}}{EmF} \right) + CO_2 \times \frac{0.02}{0.98} \times \frac{16}{44} \times f_{CH4} \qquad \text{(Eq. Y-4)}$$

Where:

CH_4 = Annual methane emissions from flared gas (metric tons CH_4/year).

CO_2 = Emission rate of CO_2 from flared gas calculated in paragraph (b)(1) of this section (metric tons/year).

EmF_{CH4} = Default CH_4 emission factor for ''Fuel Gas'' from Table C–2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH_4/MMBtu).

EmF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis).

0.02/0.98 = Correction factor for flare combustion efficiency.

16/44 = Correction factor ratio of the molecular weight of CH_4 to CO_2.

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 N_2O emissions using Equation Y–5 of this section.

$$N_2O = \left(CO_2 \times \frac{EmF_{N2O}}{EmF} \right) \qquad \text{(Eq. Y-5)}$$

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_{N2O} = Default N_2O emission factor for ''Fuel Gas'' 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 subpart (*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:

CO_2 = Annual CO_2 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).

$\%CO_2$ = Hourly average percent CO_2 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 CO_2 (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 either 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).

$\%O_2$ = 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).

$\%O_{oxy}$ = O_2 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).

$\%CO_2$ = Hourly average percent CO_2 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.

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

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).

$\%N_{2,oxy}$ = N_2 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 N_2 impurity specifications of the oxygen supply used for enrichment (percent by volume—dry basis).

$\%N_{2,exhaust}$ = Hourly average percent N_2 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 CO_2 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 CO_2 CEMS for the final exhaust stack, comply with the requirements in paragraph (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 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, you must calculate the CO_2 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 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, calculate the CO_2 emissions from each catalytic cracking unit and fluid coking unit using Equation Y–8 of this section.

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

Where:

CO_2 = Annual CO_2 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 CO_2 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 CH_4 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.

$$CH_4 = \left(CO_2 * \frac{EmF_2}{EmF_1} \right) \qquad \text{(Eq. Y-9)}$$

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 ''PetroleumProducts'' from Table C–2 of subpart C of this part (General Stationary Fuel Combustion Sources) (kg CH_4/MMBtu).

(5) Calculate N_2O 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.

$$N_2O = \left(CO_2 * \frac{EmF_3}{EmF_1} \right) \qquad \text{(Eq. Y-10)}$$

Where:

N_2O = Annual nitrous oxide emissions from coke burn-off (mt N_2O/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_3 = Default N_2O emission factor for ''PetroleumProducts'' from Table C–2 of subpart C of this part (kg N_2O/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 CO_2 emissions using the applicable methods described in paragraphs (e)(1) through (e)(3) of this section and calculate the CH_4 and N_2O 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 CO_2 emissions according to subpart C of this part (General Stationary Fuel Combustion Sources), you must calculate CO_2 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 O_2, CO_2, 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 CO_2 emissions according to the requirements of paragraphs (c)(2)(i) through (c)(2)(iii) of this section.

(3) Calculate CO_2 emissions from the catalytic reforming unit catalyst regenerator using Equation Y–11 of this section.

$$CO_2 = \sum_{1}^{n}\left[\left(CB_Q\right)_n \times CC \times \frac{44}{12} \times 0.001\right] \qquad \text{(Eq. Y-11)}$$

Where:

CO_2 = Annual CO_2 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 CO_2 to C (kg CO_2 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 CO_2 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 CO_2 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 CO_2 emissions according to subpart C of this part, you must calculate CO_2 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 CO_2 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 CO_2 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 or the sour gas feed sent for off-site sulfur recovery, 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 or the sour gas feed sent for off-site sulfur recovery, 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 the sour gas feed sent for off-site for sulfur recovery, 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 CO_2 emissions from each on-site sulfur recovery plant and for sour gas sent off-site for sulfur recovery using Equation Y–12 of this section.

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

Where:

CO_2 = Annual CO_2 emissions (metric tons/year).

F_{SG} = Volumetric flow rate of sour gas (including sour water stripper gas) fed to the sulfur recovery plant or the sour gas feed sent off-site for sulfur recovery (scf/year).

44 = Molecular weight of CO_2 (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 fed to the sulfur recovery plant or the sour gas feed sent off-site for sulfur recovery (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 CO_2 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 CO_2 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 CO_2 emissions according to subpart C of this part, you must calculate and report CO_2 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 CO_2 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 CO_2 emissions from the coke calcining unit using Equation Y–13 of this section.

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

Where:

CO_2 = Annual CO_2 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 CO_2 (kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).

(3) For all coke calcining units, use the CO_2 emissions from the coke calcining unit calculated in paragraphs (g)(1) or (g)(2), as applicable, and calculate CH_4 using the methods described in paragraph (c)(4) of this section and N_2O emissions using the methods described in paragraph (c)(5) of this section.

(h) For asphalt blowing operations, calculate CO_2 and CH_4 emissions according to the requirements in paragraph (j) of this section regardless of the CO_2 and CH_4 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 CO_2 and CH_4 emissions using Equations Y–14 and Y–15 of this section, respectively.

$$CO_2 = (Q_{AB} \times EF_{AB.CO2}) \qquad \text{(Eq. Y-14)}$$

Where:

CO_2 = Annual CO_2 emissions from uncontrolled asphalt blowing (metric tons CO_2/year).
Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).
$EF_{AB,CO2}$ = Emission factor for CO_2 from uncontrolled asphalt blowing from facility-specific test data (metric tons CO_2/MMbbl asphalt blown); default = 1,100.

$$CH_4 = \left(Q_{AB} \times EF_{AB,CH4}\right) \qquad \text{(Eq. Y-15)}$$

Where:

CH_4 = Annual methane emissions from uncontrolled asphalt blowing (metric tons CH_4/year).
Q_{AB} = Quantity of asphalt blown (million barrels per year, MMbbl/year).
EF_{AB,CH_4} = Emission factor for CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); default = 580.

(2) For asphalt blowing operations controlled by thermal oxidizer or flare, calculate CO_2 using either Equation Y–16a or Equation Y–16b of this section and calculate CH_4 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).

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

where:

CO_2 = Annual CO_2 emissions from controlled asphalt blowing (metric tons CO_2/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 CO_2 (kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).

$$CO_2 = Q_{AB} \times \left(EF_{AB,CO2} + 0.98 \times \left[\left(CEF_{AB} \times \frac{44}{12}\right) - EF_{AB,CO2}\right]\right) \qquad \text{(Eq. Y-16b)}$$

where:

CO_2 = Annual CO_2 emissions from controlled asphalt blowing (metric tons CO_2/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 CO_2 from uncontrolled asphalt blowing from facility-specific test data (metric tons CO_2/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 CO_2 (kg/kg-mole).

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

$$CH_4 = 0.02 \times \left(Q_{AB} \times EF_{AB,CH4}\right) \qquad \text{(Eq. Y-17)}$$

where:

CH_4 = Annual methane emissions from controlled asphalt blowing (metric tons CH_4/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 CH_4 from uncontrolled asphalt blowing from facility-specific test data (metric tons CH_4/MMbbl asphalt blown); default = 580.

(i) For delayed coking units, calculate the CH_4 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 CH_4 emissions from the depressurization of the coke drum or vessel regardless of the CH_4 concentration and also calculate the CH_4 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 CH_4 emissions for all delayed coking units.

$$CH_4 = \left(N \times H \times \frac{(P_{CV} + 14.7)}{14.7} \times f_{void} \times \frac{\pi \times D^2}{4} \times \frac{16}{MVC} \times MF_{CH4} \times 0.001\right) \qquad \text{(Eq. Y-18)}$$

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).

MF_{CH_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 CH_4 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 CH_4 emissions for all delayed coking units.

(j) For each process vent not covered in paragraphs (a) through (i) of this section that can reasonably be expected to contain greater than 2 percent by volume CO_2 or greater than 0.5 percent by volume of CH_4 or greater than 0.01 percent by volume (100 parts per million) of N_2O, calculate GHG emissions using Equation Y–19 of this section. You must also use Equation Y–19 of this section to calculate CH_4 emissions for catalytic reforming unit depressurization and purge vents when methane is used as the purge gas, CH_4 emissions if you elected to use the method in paragraph (i)(1) of this section, and CO_2 and/or CH_4 emissions, as applicable, if you elected this method as an alternative to the methods in paragraphs (f), (h), or (k) of this section.

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

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_2O 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 CH_4 emissions either using the methods for process vents in paragraph (j) of this section regardless of the CH_4 concentration or using Equation Y–20 of this section. Blowdown systems where the uncondensed gas stream is routed to a flare or similar control device are considered to be controlled and are not required to estimate emissions under this paragraph (k).

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

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 CH_4 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.

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

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)(3) of this section, calculate CH_4 emissions using the applicable methods in paragraphs (m)(1) and (2) 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.

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

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.

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

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_{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; 78 FR 71963, Nov. 29, 2013]

§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 combusted (in million (MM) scf/year), the annual average higher heating value of the flare gas (in mmBtu/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, 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 CO_2, CH_4, and N_2O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) A description of the method used to calculate the CO_2 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 CO_2 annual emissions as measured by the CEMS (unadjusted to remove CO_2 combustion emissions associated with additional units, if present) and the process CO_2 emissions as calculated according to § 98.253(c)(1)(ii). Report the CO_2 annual emissions associated with sources other than those from the coke burn-off in accordance with 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, $\%CO_2$, $\%CO$, and the molar volume conversion factor (in scf/kg-mole).

(8) If you use Equation Y–7a of this subpart, the annual average flow rate of inlet air and oxygen-enriched air, $\%O_2$, $\%O_{oxy}$, $\%CO_2$, 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 CH_4 emissions. If you use a unit-specific emission factor for CH_4, report the unit-specific emission factor for CH_4,

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 N_2O emissions. If you use a unit-specific emission factor for N_2O, report the unit-specific emission factor for N_2O, 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 CO_2, CH_4, and N_2O 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 on-site 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) For each on-site sulfur recovery plant, the maximum rated throughput (metric tons sulfur produced/stream day), a description of the type of sulfur recovery plant, and an indication of the method used to calculate CO_2 annual emissions for the sulfur recovery plant (*e.g.*, CO_2 CEMS, Equation Y–12, or process vent method in § 98.253(j)).

(3) The calculated CO_2 annual emissions for each on-site sulfur recovery plant, expressed in metric tons. The calculated annual CO_2 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 on-site and off-site 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 an on-site 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 CO_2 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 a unit specific correction is 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 CO_2 annual emissions as measured by the CEMS and the annual process CO_2 emissions calculated according to § 98.253(f)(1). Report the CO_2 annual emissions associated with fuel combustion in accordance with 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 CO_2, CH_4, and N_2O annual emissions for each unit, expressed in metric tons of each pollutant emitted.

(4) A description of the method used to calculate the CO_2 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 CO_2 annual emissions as measured by the CEMS and the annual process CO_2 emissions calculated according to § 98.253(g)(1).

(7) Indicate whether you use a measured value, a unit-specific emission factor or a default for CH_4 emissions. If you use a unit-specific emission factor for CH_4, the unit-specific emission factor for CH_4, 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 N_2O emissions. If you use a unit-specific emission factor for N_2O, report the unit-specific emission factor for N_2O, 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.

(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 CO_2 and CH_4 emissions for each unit, expressed in metric tons of each pollutant emitted.

(5) If you use Equation Y–14 of this subpart, the CO_2 emission factor used and the basis for the value.

(6) If you use Equation Y–15 of this subpart, the CH_4 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 CO_2 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 CH_4 emission factor used and the basis for the value.

(10) If you use Equation Y–19 of this subpart, the relevant information required under paragraph (l)(5) of this section.

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

(1) The cumulative annual CH_4 emissions (in metric tons of CH_4) for all delayed coking units at the facility.

(2) A description of the method used to calculate the CH_4 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 CH_4/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.

(6) If you use Equation Y–19 of this subpart, the relevant information required under paragraph (l)(5) of this section for each set of coke drums or vessels of the same size.

(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 CO_2, CH_4, and N_2O 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 emission 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 CH_4 emissions (in metric tons of CH_4) 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/kg-mole).

(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 CH_4 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 CH_4 emissions (in metric tons of CH_4) 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 CH_4 emissions (in metric tons of CH_4) 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 CH_4 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 annual gas generation volume (scf/yr) used to estimate the cumulative CH_4 emissions for storage tanks used to process unstabilized crude oil.

(5)–(7) [Reserved]

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

(1) The cumulative annual CH_4 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.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79164, Dec. 17, 2010; 78 FR 71963, Nov. 29, 2013]

§ 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.

[75 FR 79166, Dec. 17, 2010]

§ 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.

Subpart Z—Phosphoric Acid Production

§ 98.260 Definition of the source category.

The phosphoric acid production source category consists of facilities with a wet-process phosphoric acid process line used to produce phosphoric acid. A wet-process phosphoric acid process line is the production unit or units identified by an individual identification number in an operating permit and/or any process unit or group of process units at a facility reacting phosphate rock from a common supply source with acid.

§ 98.261 Reporting threshold.

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

§ 98.262 GHGs to report.

(a) You must report CO_2 process emissions from each wet-process phosphoric acid process line.

(b) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit following the requirements of subpart C of this part.

§ 98.263 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each wet-process phosphoric acid process line using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining a CEMS according to 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).

(b) Calculate and report under this subpart the process CO_2 emissions using the procedures in paragraphs (b)(1) and (b)(2) of this section.

(1) Calculate the annual CO_2 mass emissions from each wet-process phosphoric acid process line using the

methods in paragraphs (b)(1)(i) or (ii) of this section, as applicable.

(i) If your process measurement provides the inorganic carbon content of phosphate rock as an output, calculate and report the process CO_2 emissions from each wet-process phosphoric acid process line using Equation Z–1a of this section:

$$E_m = \sum_{i=1}^{b} \sum_{n=1}^{z} \left(IC_{n,i} * P_{n,i} \right) * \frac{2000}{2205} * \frac{44}{12} \qquad \text{(Eq. Z-1a)}$$

where:

E_m = Annual CO_2 mass emissions from a wet-process phosphoric acid process line m according to this Equation Z–1a (metric tons).

$IC_{n,i}$ = Inorganic carbon content of a grab sample batch of phosphate rock by origin i obtained during month n, from the carbon analysis results (percent by weight, expressed as a decimal fraction).

$P_{n,i}$ = Mass of phosphate rock by origin i consumed in month n by wet-process phosphoric acid process line m (tons).

z = Number of months during which the process line m operates.

b = Number of different types of phosphate rock in month, by origin. If the grab sample is a composite sample of rock from more than one origin, b = 1.

2000/2205 = Conversion factor to convert tons to metric tons.

44/12 = Ratio of molecular weights, CO_2 to carbon.

(ii) If your process measurement provides the CO_2 content directly as an output, calculate and report the process CO_2 emissions from each wet-process phosphoric acid process line using Equation Z–1b of this section:

$$E_m = \sum_{i=1}^{b} \sum_{n=1}^{z} \left(CO_{2_{n,i}} * P_{n,i} \right) * \frac{2000}{2205} \qquad \text{(Eq. Z-1b)}$$

where:

E_m = Annual CO_2 mass emissions from a wet-process phosphoric acid process line m according to this Equation Z–1b (metric tons).

$CO_{2n,i}$ = Carbon dioxide content of a grab sample batch of phosphate rock by origin i obtained during month n (percent by weight, expressed as a decimal fraction).

$P_{n,i}$ = Mass of phosphate rock by origin i consumed in month n by wet-process phosphoric acid process line m (tons).

z = Number of months during which the process line m operates.

b = Number of different types of phosphate rock in month, by origin. If the grab sample is a composite sample of rock from more than one origin, b=1.

2000/2205 = Conversion factor to convert tons to metric tons.

(2) You must determine the total emissions from the facility using Equation Z–2 of this section:

$$CO_2 = \sum_{m=1}^{p} E_m \qquad \text{(Eq. Z-2)}$$

Where:

CO_2 = Annual process CO_2 emissions from phosphoric acid production facility (metric tons/year).

E_m = Annual process CO_2 emissions from wet-process phosphoric acid process line m (metric tons/year).

p = Number of wet-process phosphoric acid process lines.

(c) If GHG emissions from a wet-process phosphoric acid process line are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66468, Oct. 28, 2010; 78 FR 71964, Nov. 29, 2013]

§ 98.264 Monitoring and QA/QC requirements.

(a) You must obtain a monthly grab sample of phosphate rock directly from the rock being fed to the process line before it enters the mill using one of the following methods. You may conduct the representative bulk sampling using a method published by a consensus standards organization, or you may use industry consensus standard practice methods, including but not limited to the Phosphate Mining States Methods Used and Adopted by the Association of Fertilizer and Phosphate Chemists (AFPC). If phosphate rock is obtained from more than one origin in a month, you must obtain a sample from each origin of rock or obtain a composite representative sample.

(b) You must determine the carbon dioxide or inorganic carbon content of each monthly grab sample of phosphate rock (consumed in the production of phosphoric acid). You may use a method published by a consensus standards organization, or you may use industry consensus standard practice methods, including but not limited to the Phosphate Mining States Methods Used and Adopted by AFPC.

(c) You must determine the mass of phosphate rock consumed each month (by origin) in each wet-process phosphoric acid process line. You can use existing plant procedures that are used for accounting purposes (such as sales records) or you can use data from existing monitoring equipment that is used to measure total mass flow of phosphorous-bearing feed under 40 CFR part 60 or part 63.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66468, Oct. 28, 2010; 78 FR 71964, Nov. 29, 2013]

§ 98.265 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter must be used in the calculations as specified in paragraphs (a) and (b) of this section.

(a) For each missing value of the inorganic carbon content or CO_2 content of phosphate rock (by origin), you must use the appropriate default factor provided in Table Z–1 of this subpart. Alternatively, you must determine a substitute data value by calculating the arithmetic average of the quality-assured values of inorganic carbon contents or CO_2 contents of phosphate rock of origin i (see Equation Z–1a or Z–1b of this subpart) from samples immediately preceding and immediately following the missing data incident. If no quality-assured data on inorganic carbon contents or CO_2 contents of phosphate rock of origin i are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for inorganic carbon contents or CO_2 contents for phosphate rock of origin i obtained after the missing data period.

(b) For each missing value of monthly mass consumption of phosphate rock (by origin), you must use the best available estimate based on all available process data or data used for accounting purposes.

[78 FR 71964, Nov. 29, 2013]

§ 98.266 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) through (f) of this section.

(a) Annual phosphoric acid production, by origin of the phosphate rock (tons).

(b) Annual phosphoric acid production capacity (tons).

(c) Annual arithmetic average percent inorganic carbon or carbon dioxide in phosphate rock from monthly records (percent by weight, expressed as a decimal fraction).

(d) Annual phosphate rock consumption from monthly measurement records by origin (tons).

(e) If you use a CEMS to measure CO_2 emissions, then you must report the information in paragraphs (e)(1) and (e)(2) of this section.

(1) The identification number of each wet-process phosphoric acid process line.

(2) The annual CO_2 emissions from each wet-process phosphoric acid process line (metric tons) and the relevant information required under 40 CFR 98.36 (e)(2)(vi) for the Tier 4 Calculation Methodology.

(f) If you do not use a CEMS to measure emissions, then you must report the information in paragraphs (f)(1) through (9) of this section.

(1) Identification number of each wet-process phosphoric acid process line.

(2) Annual CO_2 emissions from each wet-process phosphoric acid process line (metric tons) as calculated by either Equation Z–1a or Equation Z–1b of this subpart.

(3) Annual phosphoric acid permitted production capacity (tons) for each wet-process phosphoric acid process line (metric tons).

(4) Method used to estimate any missing values of inorganic carbon content or carbon dioxide content of phosphate rock for each wet-process phosphoric acid process line.

(5) Monthly inorganic carbon content of phosphate rock for each wet-process phosphoric acid process line for which Equation Z–1a is used (percent by weight, expressed as a decimal fraction), or CO_2 content (percent by weight, expressed as a decimal fraction) for which Equation Z–1b is used.

(6) Monthly mass of phosphate rock consumed, by origin, in production for each wet-process phosphoric acid process line (tons).

(7) Number of wet-process phosphoric acid process lines.

(8) Number of times missing data procedures were used to estimate phosphate rock consumption (months), inorganic carbon contents of the phosphate rock (months), and CO_2 contents of the phosphate rock (months).

(9) Annual process CO_2 emissions from phosphoric acid production facility (metric tons).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66469, Oct. 28, 2010; 78 FR 71964, Nov. 29, 2013]

§ 98.267 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (c) of this section for each wet-process phosphoric acid production facility.

(a) Monthly mass of phosphate rock consumed by origin (tons).

(b) Records of all phosphate rock purchases and/or deliveries (if vertically integrated with a mine).

(c) Documentation of the procedures used to ensure the accuracy of monthly phosphate rock consumption by origin.

§ 98.268 Definitions.

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

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71965, Nov. 29, 2013]

TABLE Z–1 TO SUBPART Z OF PART 98—DEFAULT CHEMICAL COMPOSITION OF PHOSPHATE ROCK BY ORIGIN

Origin	Total carbon (percent by weight)
Central Florida	1.6
North Florida	1.76
North Carolina (Calcined)	0.76
Idaho (Calcined)	0.60
Morocco	1.56

Subpart AA—Pulp and Paper Manufacturing

§ 98.270 Definition of source category.

(a) The pulp and paper manufacturing source category consists of facilities that produce market pulp (i.e., stand-alone pulp facilities), manufacture pulp and paper (i.e., integrated facilities), produce paper products from purchased pulp, produce secondary fiber from recycled paper, convert paper into paperboard products (e.g., containers), or operate coating and laminating processes.

(b) The emission units for which GHG emissions must be reported are listed in paragraphs (b)(1) through (b)(5) of this section:

(1) Chemical recovery furnaces at kraft and soda mills (including recovery furnaces that burn spent pulping liquor produced by both the kraft and semichemical process).

(2) Chemical recovery combustion units at sulfite facilities.

(3) Chemical recovery combustion units at stand-alone semichemical facilities.

(4) Pulp mill lime kilns at kraft and soda facilities.

(5) Systems for adding makeup chemicals ($CaCO_3$, Na_2CO_3) in the chemical recovery areas of chemical pulp mills.

§ 98.271 Reporting threshold.

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

§ 98.272 GHGs to report.

You must report the emissions listed in paragraphs (a) through (f) of this section:

(a) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each kraft or soda chemical recovery furnace.

(b) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each sulfite chemical recovery combustion unit.

(c) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each stand-alone semichemical chemical recovery combustion unit.

(d) CO_2, biogenic CO_2, CH_4, and N_2O emissions from each kraft or soda pulp mill lime kiln.

(e) CO_2 emissions from addition of makeup chemicals ($CaCO_3$, Na_2CO_3) in the chemical recovery areas of chemical pulp mills.

(f) CO_2, CH_4, and N_2O combustion emissions from each stationary combustion unit. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.273 Calculating GHG emissions.

(a) For each chemical recovery furnace located at a kraft or soda facility, you must determine CO_2, biogenic CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (a)(1) through (a)(3) of this section. CH_4 and N_2O emissions must be calculated as the sum of emissions from combustion of fossil fuels and combustion of biomass in spent liquor solids.

(1) Calculate fossil fuel-based CO_2 emissions from direct measurement of fossil fuels consumed and default emissions factors according to the Tier 1 methodology for stationary combustion sources in § 98.33(a)(1). A higher tier from § 98.33(a) may be used to calculate fossil fuel-based CO_2 emissions if the respective monitoring and QA/QC requirements described in § 98.34 are met.

(2) Calculate fossil fuel-based CH_4 and N_2O emissions from direct measurement of fossil fuels consumed, default or site-specific HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in § 98.33(c).

(3) Calculate biogenic CO_2 emissions and emissions of CH_4 and N_2O from biomass using measured quantities of spent liquor solids fired, site-specific HHV, and default emissions factors, according to Equation AA–1 of this section:

$$CO_2, CH_4, \text{ or } N_2O \text{ from biomass} = (0.907.18) * Solids * HHV * EF \qquad \text{(Eq. AA-1)}$$

Where:

CO_2, CH_4, or N_2O, from Biomass = Biogenic CO_2 emissions or emissions of CH_4 or N_2O from spent liquor solids combustion (metric tons per year).

Solids = Mass of spent liquor solids combusted (short tons per year) determined according to § 98.274(b).

HHV = Annual high heat value of the spent liquor solids (mmBtu per kilogram) determined according to § 98.274(b).

(EF) = Default emission factor for CO_2, CH_4, or N_2O, from Table AA–1 of this subpart (kg CO_2, CH_4, or N_2O per mmBtu).

0.90718 = Conversion factor from short tons to metric tons.

(b) For each chemical recovery combustion unit located at a sulfite or stand-alone semichemical facility, you must determine CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (b)(1) through (b)(4) of this section:

(1) Calculate fossil CO_2 emissions from fossil fuels from direct measurement of fossil fuels consumed and default emissions factors according to the Tier 1 Calculation Methodology for stationary combustion sources in § 98.33(a)(1). A higher tier from § 98.33(a) may be used to calculate fossil fuel-based CO_2 emissions if the respective monitoring and QA/QC requirements described in § 98.34 are met.

(2) Calculate CH_4 and N_2O emissions from fossil fuels from direct measurement of fossil fuels consumed, default or site-specific HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in § 98.33(c).

(3) Calculate biogenic CO_2 emissions using measured quantities of spent liquor solids fired and the carbon content of the spent liquor solids, according to Equation AA–2 of this section:

$$Biogenic\ CO_2 = \frac{44}{12} * \text{Solids} * \text{CC} * (0.90718) \qquad \text{(Eq. AA-2)}$$

Where:

Biogenic CO_2 = Annual CO_2 mass emissions for spent liquor solids combustion (metric tons per year).

Solids = Mass of the spent liquor solids combusted (short tons per year) determined according to § 98.274(b).

CC = Annual carbon content of the spent liquor solids, determined according to § 98.274(b) (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

44/12 = Ratio of molecular weights, CO_2 to carbon.

0.90718 = Conversion from short tons to metric tons.

(4) Calculate CH_4 and N_2O emissions from biomass using Equation AA–1 of this section and the default CH_4 and N_2O emissions factors for kraft facilities in Table AA–1 of this subpart and convert the CH_4 or N_2O emissions to metric tons of CO_2 equivalent by multiplying each annual CH_4 and N_2O emissions total by the appropriate global warming potential (GWP) factor from Table A–1 of subpart A of this part.

(c) For each pulp mill lime kiln located at a kraft or soda facility, you must determine CO_2, CH_4, and N_2O emissions using the procedures in paragraphs (c)(1) through (c)(3) of this section:

(1) Calculate CO_2 emissions from fossil fuel from direct measurement of fossil fuels consumed and default HHV and default emissions factors, according to the Tier 1 Calculation Methodology for stationary combustion sources in § 98.33(a)(1). A higher tier from § 98.33(a) may be used to calculate fossil fuel-based CO_2 emissions if the respective monitoring and QA/QC requirements described in § 98.34 are met.

(2) Calculate CH_4 and N_2O emissions from fossil fuel from direct measurement of fossil fuels consumed, default or site-specific HHV, and default emissions factors and convert to metric tons of CO_2 equivalent according to the methodology for stationary combustion sources in § 98.33(c); use the default HHV listed in Table C–1 of subpart C and the default CH_4 and N_2O emissions factors listed in Table AA–2 of this subpart.

(3) Biogenic CO_2 emissions from conversion of $CaCO_3$ to CaO are included in the biogenic CO_2 estimates calculated for the chemical recovery furnace in paragraph (a)(3) of this section.

(d) For makeup chemical use, you must calculate CO_2 emissions by using direct or indirect measurement of the quantity of chemicals added and ratios of the molecular weights of CO_2 and the makeup chemicals, according to Equation AA–3 of this section:

$$CO_2 = \left[M_{(CaCO_3)} * \frac{44}{100} + M_{(Na_2CO_3)} \frac{44}{105.99} \right] * 1000 \; kg/metric\ ton \qquad \text{(Eq. AA-3)}$$

Where:

CO_2 = CO_2 mass emissions from makeup chemicals (kilograms/yr).

M ($CaCO_3$) = Make-up quantity of $CaCO_3$ used for the reporting year (metric tons per year).

M ($NaCO_3$) = Make-up quantity of Na_2CO_3 used for the reporting year (metric tons per year).

44 = Molecular weight of CO_2.

100 = Molecular weight of $CaCO_3$.

105.99 = Molecular weight of Na_2CO_3.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79166, Dec. 17, 2010; 78 FR 71965, Nov. 29, 2013]

§ 98.274 Monitoring and QA/QC requirements.

(a) Each facility subject to this subpart must quality assure the GHG emissions data according to the applicable requirements in § 98.34. All QA/QC data must be available for inspection upon request.

(b) Fuel properties needed to perform the calculations in Equations AA–1 and AA–2 of this subpart must be determined according to paragraphs (b)(1) through (b)(3) of this section.

(1) High heat values of black liquor must be determined no less than annually using T684 om–06 Gross Heating Value of Black Liquor, TAPPI (incorporated by reference, *see* § 98.7). If measurements are performed more frequently than annually, then the high heat value used in Equation AA–1 of this subpart must be based on the average of the representative measurements made during the year.

(2) The annual mass of spent liquor solids must be determined using either of the methods specified in paragraph (b)(2)(i) or (b)(2)(ii) of this section.

(i) Measure the mass of spent liquor solids annually (or more frequently) using T–650 om–05 Solids Content of Black Liquor, TAPPI (incorporated by reference in § 98.7). If measurements are performed more frequently than annually, then the mass of spent liquor solids used in Equation AA–1 of this subpart must be based on the average of the representative measurements made during the year.

(ii) Determine the annual mass of spent liquor solids based on records of measurements made with an online measurement system that determines the mass of spent liquor solids fired in a chemical recovery furnace or chemical recovery combustion unit.

(3) Carbon analyses for spent pulping liquor must be determined no less than annually using 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). If measurements using ASTM D5373–08 are performed more frequently than annually, then the spent pulping liquor carbon content used in Equation AA–2 of this subpart must be based on the average of the representative measurements made during the year.

(c) Each facility must keep records that include a detailed explanation of how company records of measurements are used to estimate GHG emissions. The owner or operator must also document the procedures used to ensure the accuracy of the measurements of fuel, spent liquor solids, and makeup chemical usage, 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 must be recorded and the technical basis for these estimates must be provided. The procedures used to convert spent pulping liquor flow rates to units of mass (i.e., spent liquor solids firing rates) also must be documented.

(d) Records must be made available upon request for verification of the calculations and measurements.

§98.275 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions during unit operation or if a required sample is not taken), a substitute data value for the missing parameter shall be used in the calculations, according to the requirements of paragraphs (a) through (c) of this section:

(a) There are no missing data procedures for measurements of heat content and carbon content of spent pulping liquor. A re-test must be performed if the data from any annual measurements are determined to be invalid.

(b) For missing measurements of the mass of spent liquor solids or spent pulping liquor flow rates, use the lesser value of either the maximum mass or fuel flow rate for the combustion unit, or the maximum mass or flow rate that the fuel meter can measure.

(c) For the use of makeup chemicals (carbonates), the substitute data value shall be the best available estimate of makeup chemical consumption, based on available data (e.g., past accounting records, production rates). The owner or operator shall document and keep records of the procedures used for all such estimates.

§98.276 Data reporting requirements.

In addition to the information required by §98.3(c) and the applicable information required by §98.36, each annual report must contain the information in paragraphs (a) through (k) of this section as applicable:

(a) Annual emissions of CO_2, biogenic CO_2, CH_4, biogenic CH_4 N_2O, and biogenic N_2O (metric tons per year).

(b) Annual quantities fossil fuels by type used in chemical recovery furnaces and chemical recovery combustion units in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(c) Annual mass of the spent liquor solids combusted (short tons per year), and basis for determining the annual mass of the spent liquor solids combusted (whether based on T650 om-05 Solids Content of Black Liquor, TAPPI (incorporated by reference, *see* §98.7) or an online measurement system).

(d) The high heat value (HHV) of the spent liquor solids used in Equation AA–1 of this subpart (mmBtu per kilogram).

(e) The default emission factor for CO_2, CH_4, or N_2O, used in Equation AA–1 of this subpart (kg CO_2, CH_4, or N_2O per mmBtu).

(f) The carbon content (CC) of the spent liquor solids, used in Equation AA–2 of this subpart (percent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).

(g) Annual quantities of fossil fuels by type used in pulp mill lime kilns in short tons for solid fuels, gallons for liquid fuels and scf for gaseous fuels.

(h) Make-up quantity of $CaCO_3$ used for the reporting year (metric tons per year) used in Equation AA–3 of this subpart.

(i) Make-up quantity of Na_2CO_3 used for the reporting year (metric tons per year) used in Equation AA–3 of this subpart.

(j) Annual steam purchases (pounds of steam per year).

(k) Total annual production of unbleached virgin chemical pulp produced onsite during the reporting year in air-dried metric tons per year. This total annual production value is the sum of all kraft, semichemical, soda, and sulfite pulp produced onsite, prior to bleaching, through all virgin pulping lines. Do not include mechanical pulp or secondary fiber repulped for paper production in the virgin pulp production total.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79166, Dec. 17, 2010; 78 FR 71965, Nov. 29, 2013]

§98.277 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the records in paragraphs (a) through (f) of this section.

(a) GHG emission estimates (including separate estimates of biogenic CO_2)

for each emissions source listed under § 98.270(b).

(b) Annual analyses of spent pulping liquor HHV for each chemical recovery furnace at kraft and soda facilities.

(c) Annual analyses of spent pulping liquor carbon content for each chemical recovery combustion unit at a sulfite or semichemical pulp facility.

(d) Annual quantity of spent liquor solids combusted in each chemical recovery furnace and chemical recovery combustion unit, and the basis for detemining the annual quantity of the spent liquor solids combusted (whether based on T650 om–05 Solids Content of Black Liquor, TAPPI (incorporated by reference, *see* § 98.7) or an online measurement system). If an online measurement system is used, you must retain records of the calculations used to determine the annual quantity of spent liquor solids combusted from the continuous measurements.

(e) Annual steam purchases.

(f) Annual quantities of makeup chemicals used.

§ 98.278 Definitions.

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

TABLE AA–1 TO SUBPART AA OF PART 98—KRAFT PULPING LIQUOR EMISSIONS FACTORS FOR BIOMASS-BASED CO_2, CH_4, AND N_2O

OOD FURNISH

Wood furnish	Biomass-based emissions factors (kg/mmBtu HHV)		
	[a] CO_2	CH_4	N_2O
North American Softwood	94.4	0.0019	0.00042
North American Hardwood	93.7	0.0019	0.00042
Bagasse	95.5	0.0019	0.00042
Bamboo	93.7	0.0019	0.00042
Straw	95.1	0.0019	0.00042

[a] Includes emissions from both the recovery furnace and pulp mill lime kiln.

[78 FR 71965, Nov. 29, 2013]

TABLE AA–2 TO SUBPART AA OF PART 98—KRAFT LIME KILN AND CALCINER EMISSIONS FACTORS FOR CH_4 AND N_2O

Fuel	Fossil fuel-based emissions factors (kg/mmBtu HHV)			
	Kraft lime kilns		Kraft calciners	
	CH_4	N_2O	CH_4	N_2O
Residual Oil (any type)	0.0027	0	0.0027	0.0003
Distillate Oil (any type)	0.0027	0	0.0027	0.0004
Natural Gas	0.0027	0	0.0027	0.0001
Biogas	0.0027	0	0.0027	0.0001
Petroleum coke	0.0027	0	[a]NA	[a]NA
Other Fuels	See Table C–2	0	See Table C–2	See Table C–2

[a] Emission factors for kraft calciners are not available.

[78 FR 71965, Nov. 29, 2013]

Subpart BB—Silicon Carbide Production

§ 98.280 Definition of the source category.

Silicon carbide production includes any process that produces silicon carbide for abrasive purposes.

§ 98.281 Reporting threshold.

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

§98.282 GHGs to report.

You must report:

(a) CO_2 process emissions from all silicon carbide process units or furnaces combined.

(b) CO_2, CH_4, and N_2O emissions from each stationary combustion unit. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71966, Nov. 29, 2013]

§98.283 Calculating GHG emissions.

You must calculate and report the combined annual process CO_2 emissions from all silicon carbide process units and production furnaces using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the combined annual process CO_2 emissions by operating and maintaining CEMS according to 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).

(b) Calculate and report under this subpart the combined annual process CO_2 emissions using the procedures in paragraphs (b)(1) and (b)(2) of this section.

(1) Use Equation BB–1 of this section to calculate the facility-specific emissions factor for determining CO_2 emissions. The carbon content must be measured monthly and used to calculate a monthly CO_2 emissions factor:

$$EF_{CO2,n} = 0.65 * CCF_n * \left(\frac{44}{12}\right) \qquad \text{(Eq. BB-1)}$$

Where:

$EF_{CO2,n}$ = CO_2 emissions factor in month n (metric tons CO_2/metric ton of petroleum coke consumed).

0.65 = Adjustment factor for the amount of carbon in silicon carbide product (assuming 35 percent of carbon input is in the carbide product).

CCF_n = Carbon content factor for petroleum coke consumed in month n from the supplier or as measured by the applicable method incorporated by reference in §98.7 according to §98.284(c) (percent by weight expressed as a decimal fraction).

44/12 = Ratio of molecular weights, CO_2 to carbon.

(2) Calculate annual CO_2 process emissions from the silicon carbide production facility according to Equation BB–2 of this section:

$$CO_2 = \sum_{n=1}^{12}\left[T_n * EF_{CO2,n}\right] * \frac{2000}{2205} \qquad \text{(Eq. BB-2)}$$

Where:

CO_2 = Annual CO_2 emissions from silicon carbide production facility (metric tons CO_2).

T_n = Petroleum coke consumption in calendar month n (tons).

$EF_{CO2,n}$ = CO_2 emissions factor from month n (calculated in Equation BB–1 of this section).

2000/2205 = Conversion factor to convert tons to metric tons.

n = Number of month.

(c) If GHG emissions from a silicon carbide production furnace or process unit are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71966, Nov. 29, 2013]

§ 98.284 Monitoring and QA/QC requirements.

(a) You must measure your consumption of petroleum coke using plant instruments used for accounting purposes including direct measurement weighing the petroleum coke fed into your process (by belt scales or a similar device) or through the use of purchase records.

(b) You must document the procedures used to ensure the accuracy of monthly petroleum coke consumption measurements.

(c) For CO_2 process emissions, you must determine the monthly carbon content of the petroleum coke using reports from the supplier. Alternatively, facilities can measure monthly carbon contents of the petroleum coke using ASTM D3176–89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, *see* § 98.7) and 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).

(d) For quality assurance and quality control of the supplier data, you must conduct an annual measurement of the carbon content of the petroleum coke using ASTM D3176–89 and 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).

§ 98.285 Procedures for estimating missing data.

For the petroleum coke input procedure in § 98.283(b), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the monthly carbon content of petroleum coke, the substitute data value shall be the arithmetic average of the quality-assured values of carbon contents immediately preceding and immediately following the missing data incident. If no quality-assured data on carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.

(b) For each missing value of the monthly petroleum coke consumption, the substitute data value shall be the best available estimate of the petroleum coke consumption based on all available process data or information used for accounting purposes (such as purchase records).

§ 98.286 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable for each silicon carbide production facility.

(a) If a CEMS is used to measure process CO_2 emissions, you must report under this subpart the relevant information required for the Tier 4 Calculation Methodology in § 98.36 and the information listed in this paragraph (a):

(1) Annual consumption of petroleum coke (tons).

(2) Annual production of silicon carbide (tons).

(3) Annual production capacity of silicon carbide (tons).

(b) If a CEMS is not used to measure process CO_2 emissions, you must report the information in paragraph (b)(1) through (8) of this section for all silicon carbide process units or production furnaces combined:

(1) Monthly consumption of petroleum coke (tons).

(2) *Annual production of* silicon carbide (tons).

(3) Annual production capacity of silicon carbide (tons).

(4) Carbon content factor of petroleum coke from the supplier or as measured by the applicable method in § 98.284(c) for each month (percent by weight expressed as a decimal fraction).

(5) Whether carbon content of the petroleum coke is based on reports from the supplier or through self measurement using applicable ASTM standard method.

(6) CO_2 emissions factor calculated for each month (metric tons CO_2/metric ton of petroleum coke consumed).

(7) Sampling analysis results for carbon content of consumed petroleum coke as determined for QA/QC of supplier data under § 98.284(d) (percent by weight expressed as a decimal fraction).

(8) Number of times in the reporting year that missing data procedures were followed to measure the carbon contents of petroleum coke (number of months) and petroleum coke consumption (number of months).

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71966, Nov. 29, 2013]

§ 98.287 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each silicon carbide production facility.

(a) If a CEMS is used to measure CO_2 emissions, you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37 and the information listed in this paragraph (a):

(1) Records of all petroleum coke purchases.

(2) Annual operating hours.

(b) If a CEMS is not used to measure emissions, you must retain records for the information listed in this paragraph (b):

(1) Records of all analyses and calculations conducted for reported data listed in § 98.286(b).

(2) Records of all petroleum coke purchases.

(3) Annual operating hours.

§ 98.288 Definitions.

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

Subpart CC—Soda Ash Manufacturing

§ 98.290 Definition of the source category.

(a) A soda ash manufacturing facility is any facility with a manufacturing line that produces soda ash by one of the methods in paragraphs (a)(1) through (3) of this section:

(1) Calcining trona.

(2) Calcining sodium sesquicarbonate.

(3) Using a liquid alkaline feedstock process that directly produces CO_2.

(b) In the context of the soda ash manufacturing sector, ''calcining'' means the thermal/chemical conversion of the bicarbonate fraction of the feedstock to sodium carbonate.

§ 98.291 Reporting threshold.

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

§ 98.292 GHGs to report.

You must report:

(a) CO_2 process emissions from each soda ash manufacturing line combined.

(b) CO_2 combustion emissions from each soda ash manufacturing line.

(c) CH_4 and N_2O combustion emissions from each soda ash manufacturing line. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(d) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than soda ash manufacturing lines. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.293 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions from each soda ash manufacturing line using the procedures specified in paragraph (a) or (b) of this section.

(a) For each soda ash manufacturing line that meets the conditions specified in §98.33(b)(4)(ii) or (b)(4)(iii), you must calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to 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).

(b) For each soda ash manufacturing line that is not subject to the requirements in paragraph (a) of this section, calculate and report the process CO_2 emissions from the soda ash manufacturing line by using the procedure in either paragraphs (b)(1), (b)(2), or (b)(3) of this section; and the combustion CO_2 emissions using the procedure in paragraph (b)(4) of this section.

(1) Calculate and report under this subpart the combined process and combustion CO_2 emissions by operating and maintaining a CEMS to measure CO_2 emissions according to 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).

(2) Use either Equation CC–1 or Equation CC–2 of this section to calculate annual CO_2 process emissions from each manufacturing line that calcines trona to produce soda ash:

$$E_k = \sum_{n=1}^{12} \left[\left(IC_T \right)_n * \left(T_t \right)_n \right] * \frac{2000}{2205} * \frac{0.097}{1} \qquad \text{(Eq. CC-1)}$$

$$E_k = \sum_{n=1}^{12} \left[\left(IC_{sa} \right)_n * \left(T_{sa} \right)_n \right] * \frac{2000}{2205} * \frac{0.138}{1} \qquad \text{(Eq. CC-2)}$$

Where:

E_k = Annual CO_2 process emissions from each manufacturing line, k (metric tons).

$(IC_T)_n$ = Inorganic carbon content (percent by weight, expressed as a decimal fraction) in trona input, from the carbon analysis results for month n. This represents the ratio of trona to trona ore.

$(IC_{sa})_n$ = Inorganic carbon content (percent by weight, expressed as a decimal fraction) in soda ash output, from the carbon analysis results for month n. This represents the purity of the soda ash produced.

$(T_t)_n$ = Mass of trona input in month n (tons).

$(T_{sa})_n$ = Mass of soda ash output in month n (tons).

2000/2205 = Conversion factor to convert tons to metric tons.

0.097/1 = Ratio of ton of CO_2 emitted for each ton of trona.

0.138/1 = Ratio of ton of CO_2 emitted for each ton of soda ash produced.

(3) *Site-specific emission factor method.* Use Equations CC–3, CC–4, and CC–5 of this section to determine annual CO_2 process emissions from manufacturing lines that use the liquid alkaline feedstock process to produce soda ash. You must conduct an annual performance test and measure CO_2 emissions and flow rates at all process vents from the mine water stripper/evaporator for each manufacturing line and calculate CO_2 emissions as described in paragraphs (b)(3)(i) through (b)(3)(iv) of this section.

(i) During the performance test, you must measure the process vent flow from each process vent during the test and calculate the average rate for the test period in metric tons per hour.

(ii) Using the test data, you must calculate the hourly CO_2 emission rate using Equation CC–3 of this section:

$$ER_{CO2} = \left[\left(C_{co2} * 10000\right) * 2.59x10^{-9} * 44\right] * (Q * 60) * 4.53x10^{-4} \qquad \text{(Eq. CC-3)}$$

Where:

ER_{CO2} = CO_2 mass emission rate (metric tons/hour).

C_{CO2} = Hourly CO_2 concentration (percent CO_2) as determined by §98.294(c).

10000 = Parts per million per percent

$2.59{\times}10^{-9}$ = Conversion factor (pounds-mole/dscf/ppm).

44 = Pounds per pound-mole of carbon dioxide.

Q = Stack gas volumetric flow rate per minute (dscfm).

60 = Minutes per hour

4.53×10^{-4} = Conversion factor (metric tons/pound)

(iii) Using the test data, you must calculate a CO_2 emission factor for the process using Equation CC–4 of this section:

$$EF_{CO2} = \frac{ER_{CO2}}{\left(V_t * 4.53x10^{-4}\right)} \qquad \text{(Eq. CC-4)}$$

Where:

EF_{CO2} = CO_2 emission factor (metric tons CO_2/metric ton of process vent flow from mine water stripper/evaporator).

ER_{CO2} = CO_2 mass emission rate (metric tons/hour).

V_t = Process vent flow rate from mine water stripper/evaporator during annual performance test (pounds/hour).

4.53×10^{-4} = Conversion factor (metric tons/pound)

(iv) You must calculate annual CO_2 process emissions from each manufacturing line using Equation CC–5 of this section:

$$E_k = EF_{CO2} * \left(V_a * 0.453\right) * H \qquad \text{(Eq. CC-5)}$$

Where:

E_k = Annual CO_2 process emissions for each manufacturing line, k (metric tons).

EF_{CO2} = CO_2 emission factor (metric tons CO_2/metric ton of process vent flow from mine water stripper/evaporator).

V_a = Annual process vent flow rate from mine water stripper/evaporator (thousand pounds/hour).

H = Annual operating hours for the each manufacturing line.

0.453 = Conversion factor (metric tons/thousand pounds).

(4) Calculate and report under subpart C of this part (General Stationary Fuel Combustion Sources) the combustion CO_2, CH_4, and N_2O emissions in the soda ash manufacturing line according to the applicable requirements in subpart C.

§98.294 Monitoring and QA/QC requirements.

Section 98.293 provides three different procedures for emission calculations. The appropriate paragraphs (a) through (c) of this section should be used for the procedure chosen.

(a) If you determine your emissions using §98.293(b)(2) (Equation CC–1 of this subpart) you must:

(1) Determine the monthly inorganic carbon content of the trona from a weekly composite analysis for each soda ash manufacturing line, using a modified version of ASTM E359–00 (Reapproved 2005)e1, Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate) (incorporated by reference, see §98.7). ASTM E359–00(Reapproved 2005) e1 is designed to measure the total alkalinity in soda ash not in trona. The modified method referred to above adjusts the regular ASTM method to express the results in terms of trona. Although ASTM E359–00 (Reapproved 2005) e1 uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of trona input produced by each soda ash manufacturing line on a monthly basis using belt scales or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of trona consumed.

(b) If you calculate CO_2 process emissions based on soda ash production (§ 98.293(b)(2) Equation CC–2 of this subpart), you must:

(1) Determine the inorganic carbon content of the soda ash (i.e., soda ash purity) using ASTM E359–00 (Reapproved 2005) e1 Standard Test Methods for Analysis of Soda Ash (Sodium Carbonate) (incorporated by reference, see § 98.7). Although ASTM E359–00 (Reapproved 2005) e1 uses manual titration, suitable autotitrators may also be used for this determination.

(2) Measure the mass of soda ash produced by each soda ash manufacturing line on a monthly basis using belt scales, by weighing the soda ash at the truck or rail loadout points of your facility, or methods used for accounting purposes.

(3) Document the procedures used to ensure the accuracy of the monthly measurements of soda ash produced.

(c) If you calculate CO_2 emissions using the site-specific emission factor method in § 98.293(b)(3), you must:

(1) Conduct an annual performance test that is based on representative performance (i.e., performance based on normal operating conditions) of the affected process.

(2) Sample the stack gas and conduct three emissions test runs of 1 hour each.

(3) Conduct the stack test using EPA Method 3A at 40 CFR part 60, appendix A–2 to measure the CO_2 concentration, Method 2, 2A, 2C, 2D, or 2F at 40 CFR part 60, appendix A–1 or Method 26 at 40 CFR part 60, appendix A–2 to determine the stack gas volumetric flow rate. All QA/QC procedures specified in the reference test methods and any associated performance specifications apply. For each test, the facility must prepare an emission factor determination report that must include the items in paragraphs (c)(3)(i) through (c)(3)(iii) of this section.

(i) Analysis of samples, determination of emissions, and raw data.

(ii) All information and data used to derive the emissions factor(s).

(iii) You must determine the average process vent flow rate from the mine water stripper/evaporater during each test and document how it was determined.

(4) You must also determine the annual vent flow rate from the mine water stripper/evaporater from monthly information using the same plant instruments or procedures used for accounting purposes (i.e., volumetric flow meter).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66469, Oct. 28, 2010]

§ 98.295 Procedures for estimating missing data.

For the emission calculation methodologies in § 98.293(b)(2) and (b)(3), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., inorganic carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) through (d) of this section. You must document and keep records of the procedures used for all such missing value estimates.

(a) For each missing value of the weekly composite of inorganic carbon content of either soda ash or trona, the substitute data value shall be the arithmetic average of the quality-assured values of inorganic carbon contents from the week immediately preceding and the week immediately following the missing data incident. If no quality-assured data on inorganic carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.

(b) For each missing value of either the monthly soda ash production or the trona consumption, the substitute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or data used for accounting purposes.

(c) For each missing value collected during the performance test (hourly CO_2 concentration, stack gas volumetric flow rate, or average process vent flow from mine water stripper/evaporator during performance test), you must repeat the annual performance test following the calculation and monitoring and QA/QC requirements under §§98.293(b)(3) and 98.294(c).

(d) For each missing value of the monthly process vent flow rate from mine water stripper/evaporator, the subsititute data value shall be the best available estimate(s) of the parameter(s), based on all available process data or the lesser of the maximum capacity of the system or the maximum rate the meter can measure.

§98.296 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as appropriate for each soda ash manufacturing facility.

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required under §98.36 and the following information in this paragraph (a):

(1) Annual consumption of trona or liquid alkaline feedstock for each manufacturing line (tons).

(2) Annual production of soda ash for each manufacturing line (tons).

(3) Annual production capacity of soda ash for each manufacturing line (tons).

(4) Identification number of each manufacturing line.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in this paragraph (b):

(1) Identification number of each manufacturing line.

(2) Annual process CO_2 emissions from each soda ash manufacturing line (metric tons).

(3) Annual production of soda ash for each manufacturing line (tons).

(4) Annual production capacity of soda ash for each manufacturing line (tons).

(5) Monthly consumption of trona or liquid alkaline feedstock for each manufacturing line (tons).

(6) Monthly production of soda ash for each manufacturing line (tons).

(7) Inorganic carbon content factor of trona or soda ash (depending on use of Equations CC–1 or CC–2 of this subpart) as measured by the applicable method in §98.294(b) or (c) for each month (percent by weight expressed as a decimal fraction).

(8) Whether CO_2 emissions for each manufacturing line were calculated using a trona input method as described in Equation CC–1 of this subpart, a soda ash output method as described in Equation CC–2 of this subpart, or a site-specific emission factor method as described in Equations CC–3 through CC–5 of this subpart.

(9) Number of manufacturing lines located used to produce soda ash.

(10) If you produce soda ash using the liquid alkaline feedstock process and use the site-specific emission factor method (§98.293(b)(3)) to estimate emissions then you must report the following relevant information for each manufacturing line or stack:

(i) Stack gas volumetric flow rate during performance test (dscfm).

(ii) Hourly CO_2 concentration during performance test (percent CO_2).

(iii) CO_2 emission factor (metric tons CO_2/metric tons of process vent flow from mine water stripper/evaporator).

(iv) CO_2 mass emission rate during performance test (metric tons/hour).

(11) Number of times missing data procedures were used and for which parameter as specified in this paragraph (b)(11):

(i) Trona or soda ash (number of months).

(ii) Inorganic carbon contents of trona or soda ash (weeks).

(iii) Process vent flow rate from mine water stripper/evaporator (number of months).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66469, Oct. 28, 2010]

§98.297 Records that must be retained.

In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each soda ash manufacturing line.

(a) If a CEMS is used to measure CO_2 emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology specified in subpart C of this part and the information listed in this paragraph (a):

(1) Monthly production of soda ash (tons)

(2) Monthly consumption of trona or liquid alkaline feedstock (tons)

(3) Annual operating hours (hours).

(b) If a CEMS is not used to measure emissions, then you must retain records for the information listed in this paragraph (b):

(1) Records of all analyses and calculations conducted for determining all reported data as listed in § 98.296(b).

(2) If using Equation CC–1 or CC–2 of this subpart, weekly inorganic carbon content factor of trona or soda ash, depending on method chosen, as measured by the applicable method in § 98.294(b) (percent by weight expressed as a decimal fraction).

(3) Annual operating hours for each manufacturing line used to produce soda ash (hours).

(4) You must document the procedures used to ensure the accuracy of the monthly trona consumption or soda ash production measurements including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(5) If you produce soda ash using the liquid alkaline feedstock process and use the site-specific emission factor method to estimate emissions (§ 98.293(b)(3)) then you must also retain the following relevant information:

(i) Records of performance test results.

(ii) You must document the procedures used to ensure the accuracy of the annual average vent flow measurements including, but not limited to, calibration of flow rate meters and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.298 Definitions.

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

Subpart DD—Electrical Transmission and Distribution Equipment Use

SOURCE: 75 FR 74855, Dec. 1, 2010, unless otherwise noted.

§ 98.300 Definition of the source category.

(a) The electrical transmission and distribution equipment use source category consists of all electric transmission and distribution equipment and servicing inventory insulated with or containing sulfur hexafluoride (SF_6) or perfluorocarbons (PFCs) used within an electric power system. Electric transmission and distribution equipment and servicing inventory includes, but is not limited to:

(1) Gas-insulated substations.

(2) Circuit breakers.

(3) Switchgear, including closed-pressure and hermetically sealed-pressure switchgear and gas-insulated lines containing SF_6 or PFCs.

(4) Gas containers such as pressurized cylinders.

(5) Gas carts.

(6) Electric power transformers.

(7) Other containers of SF_6 or PFC.

§ 98.301 Reporting threshold.

(a) You must report GHG emissions from an electric power system if the total nameplate capacity of SF_6 and PFC containing equipment (excluding hermetically sealed-pressure equipment) located within the facility, when added to the total nameplate capacity of SF_6 and PFC containing equipment (excluding hermetically sealed-pressure equipment) that is not located within the facility but is under common ownership or control, exceeds 17,820 pounds and the facility meets the requirements of § 98.2(a)(1).

(b) A facility other than an electric power system that is subject to this part because of emissions from any other source category listed in Table A–3 or A–4 in subpart A of this part is not required to report emissions under subpart DD of this part unless the total nameplate capacity of SF_6 and PFC containing equipment located within that facility exceeds 17,820 pounds.

§ 98.302 GHGs to report.

You must report total SF_6 and PFC emissions from your facility (including emissions from fugitive equipment leaks, installation, servicing, equipment decommissioning and disposal, and from storage cylinders) resulting from the transmission and distribution servicing inventory and equipment listed in § 98.300(a). For acquisitions of equipment containing or insulated with SF_6 or PFCs, you must report emissions from the equipment after the title to the equipment is transferred to the electric power transmission or distribution entity.

§ 98.303 Calculating GHG emissions.

(a) Calculate the annual SF_6 and PFC emissions using the mass-balance approach in Equation DD–1 of this section:

$$\text{User Emissions} = (\text{Decrease in } SF_6 \text{ Inventory}) + (\text{Acquisitions of } SF_6) - (\text{Disbursements of } SF_6) - (\text{Net Increase in Total Nameplate Capacity of Equipment Operated}) \qquad \text{(Eq. DD-1)}$$

where:

Decrease in SF_6 Inventory = (pounds of SF_6 stored in containers, but not in energized equipment, at the beginning of the year) − (pounds of SF_6 stored in containers, but not in energized equipment, at the end of the year).

Acquisitions of SF_6 = (pounds of SF_6 purchased from chemical producers or distributors in bulk) + (pounds of SF_6 purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear) + (pounds of SF_6 returned to facility after off-site recycling).

Disbursements of SF_6 = (pounds of SF_6 in bulk and contained in equipment that is sold to other entities) + (pounds of SF_6 returned to suppliers) + (pounds of SF_6 sent off site for recycling) + (pounds of SF_6 sent off-site for destruction).

Net Increase in Total Nameplate Capacity of Equipment Operated = (The Nameplate Capacity of new equipment in pounds, including hermetically sealed-pressure switchgear) − (Nameplate Capacity of retiring equipment in pounds, including hermetically sealed-pressure switchgear). (Note that Nameplate Capacity refers to the full and proper charge of equipment rather than to the actual charge, which may reflect leakage).

(b) Use Equation DD–1 of this section to estimate emissions of PFCs from power transformers, substituting the relevant PFC(s) for SF_6 in the equation.

§ 98.304 Monitoring and QA/QC requirements.

(a) For calendar year 2011 monitoring, you may follow the provisions of § 98.3(d)(1) through (d)(2) for best available monitoring methods rather than follow the monitoring requirements of this section. For purposes of this subpart, any reference in § 98.3(d)(1) through (d)(2) to 2010 means 2011, to March 31 means June 30, and to April 1 means July 1. Any reference to the effective date in § 98.3(d)(1) through (d)(2) means February 28, 2011.

(b) You must adhere to the following QA/QC methods for reviewing the completeness and accuracy of reporting:

(1) Review inputs to Equation DD–1 of this section to ensure inputs and outputs to the company's system are included.

(2) Do not enter negative inputs and confirm that negative emissions are not calculated. However, the Decrease in SF_6 Inventory and the Net Increase in Total Nameplate Capacity may be calculated as negative numbers.

(3) Ensure that beginning-of-year inventory matches end-of-year inventory from the previous year.

(4) Ensure that in addition to SF_6 purchased from bulk gas distributors, SF_6 purchased from Original Equipment Manufacturers (OEM) and SF_6 returned to the facility from off-site recycling are also accounted for among the total additions.

(c) Ensure the following QA/QC methods are employed throughout the year:

(1) Ensure that cylinders returned to the gas supplier are consistently weighed on a scale that is certified to be accurate and precise to within 2 pounds of true weight and is periodically recalibrated per the manufacturer's specifications. Either measure residual gas (the amount of gas remaining in returned cylinders) or have the gas supplier measure it. If the gas supplier weighs the residual gas, obtain from the gas supplier a detailed monthly accounting, within ± 2 pounds, of residual gas amounts in the cylinders returned to the gas supplier.

(2) Ensure that cylinders weighed for the beginning and end of year inventory measurements are weighed on a scale that is certified to be accurate and precise to within 2 pounds of true weight and is periodically recalibrated per the manufacturer's specifications. All scales used to measure quantities that are to be reported under § 98.306 must be calibrated using calibration procedures specified by the scale manufacturer. Calibration must be performed prior to the first reporting year. After the initial calibration, recalibration must be performed at the minimum frequency specified by the manufacturer.

(3) Ensure all substations have provided information to the manager compiling the emissions report (if it is not already handled through an electronic inventory system).

(d) GHG Monitoring Plans, as described in § 98.3(g)(5), must be completed by April 1, 2011.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71966, Nov. 29, 2013]

§ 98.305 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Replace missing data, if needed, based on data from equipment with a similar nameplate capacity for SF_6 and PFC, and from similar equipment repair, replacement, and maintenance operations.

§ 98.306 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each electric power system, by chemical:

(a) Nameplate capacity of equipment (pounds) containing SF_6 and nameplate capacity of equipment (pounds) containing each PFC:

(1) Existing at the beginning of the year (excluding hermetically sealed-pressure switchgear).

(2) New during the year (all SF_6-insulated equipment, including hermetically sealed-pressure switchgear).

(3) Retired during the year (all SF_6-insulated equipment, including hermetically sealed-pressure switchgear).

(b) Transmission miles (length of lines carrying voltages above 35 kilovolt).

(c) Distribution miles (length of lines carrying voltages at or below 35 kilovolt).

(d) Pounds of SF_6 and PFC stored in containers, but not in energized equipment, at the beginning of the year.

(e) Pounds of SF6 and PFC stored in containers, but not in energized equipment, at the end of the year.

(f) Pounds of SF_6 and PFC purchased in bulk from chemical producers or distributors.

(g) Pounds of SF_6 and PFC purchased from equipment manufacturers or distributors with or inside equipment, including hermetically sealed-pressure switchgear.

(h) Pounds of SF_6 and PFC returned to facility after off-site recycling.

(i) Pounds of SF_6 and PFC in bulk and contained in equipment sold to other entities.

(j) Pounds of SF_6 and PFC returned to suppliers.

(k) Pounds of SF_6 and PFC sent offsite for recycling.

(l) Pounds of SF_6 and PFC sent offsite for destruction.

§ 98.307 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain records of the information reported and listed in § 98.306.

§ 98.308 Definitions.

Except as specified in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Facility, with respect to an electric power system, means the electric power system as defined in this paragraph. An electric power system is comprised of all electric transmission and distribution equipment insulated with or containing SF_6 or PFCs that is linked through electric power transmission or distribution lines and functions as an integrated unit, that is owned, serviced, or maintained by a single electric power transmission or distribution entity (or multiple entities with a common owner), and that is located between: (1) The point(s) at which electric energy is obtained from an electricity generating unit or a different electric power transmission or distribution entity that does not have a common owner, and (2) the point(s) at which any customer or another electric power transmission or distribution entity that does not have a common owner receives the electric energy. The facility also includes servicing inventory for such equipment that contains SF_6 or PFCs.

Electric power transmission or distribution entity means any entity that transmits, distributes, or supplies electricity to a consumer or other user, including any company, electric cooperative, public electric supply corporation, a similar Federal department (including the Bureau of Reclamation or the Corps of Engineers), a municipally owned electric department offering service to the public, an electric public utility district, or a jointly owned electric supply project.

Operator, for the purposes of this subpart, means any person who operates or supervises a facility, excluding a person whose sole responsibility is to ensure reliability, balance load or otherwise address electricity flow.

Subpart EE—Titanium Dioxide Production

§98.310 Definition of the source category.

The titanium dioxide production source category consists of facilities that use the chloride process to produce titanium dioxide.

§98.311 Reporting threshold.

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

§98.312 GHGs to report.

(a) You must report CO_2 process emissions from each chloride process line as required in this subpart.

(b) You must report CO_2, CH_4, and N_2O emissions from each stationary combustion unit under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§98.313 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions for each chloride process line using the procedures in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process CO_2 emissions by operating and maintaining a CEMS according to 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).

(b) Calculate and report under this subpart the annual process CO_2 emissions for each chloride process line by determining the mass of calcined petroleum coke consumed in each line as specified in paragraphs (b)(1) through (b)(3) of this section. Use Equation EE–1 of this section to calulate annual combined process CO_2 emissions from all process lines and use Equation EE–2 of this section to calculate annual process CO_2 emissions for each process line. If your facility generates carbon-containing waste, use Equation EE–3 of this section to estimate the annual quantity of carbon-containing waste generated and its carbon contents according to §98.314(e) and (f):

(1) You must calculate the annual CO_2 process emissions from all process lines at the facility using Equation EE–1 of this section:

$$CO_2 = \sum_{p=1}^{m} E_p \qquad \text{(Eq. EE-1)}$$

Where:

CO_2 = Annual CO_2 emissions from titanium dioxide production facility (metric tons/year).

E_p = Annual CO_2 emissions from chloride process line p (metric tons), determined using Equation EE–2 of this section.

p = Process line.

m = Number of separate chloride process lines located at the facility.

(2) You must calculate the annual CO_2 process emissions from each process lines at the facility using Equation EE–2 of this section:

$$E_p = \sum_{n=1}^{12} \frac{44}{12} * C_{p,n} * \frac{2000}{2205} * CCF_n \qquad \text{(Eq. EE-2)}$$

Where:

E_p = Annual CO_2 mass emissions from chloride process line p (metric tons).

$C_{p,n}$ = Calcined petroleum coke consumption for process line p in month n (tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

2000/2205 = Conversion of tons to metric tons.

CCF_n = Carbon content factor for petroleum coke consumed in month n from the supplier or as measured by the applicable method incorporated by reference in § 98.7 according to § 98.314(c) (percent by weight expressed as a decimal fraction).

n = Number of month.

(3) If facility generates carbon-containing waste, you must calculate the total annual quantity of carbon-containing waste produced from all process lines using Equation EE–3 of this section and its carbon contents according to § 98.314(e) and (f):

$$TWC = \sum_{p=1}^{m} \sum_{n=1}^{12} WC_{p,n} \qquad \text{(Eq. EE-3)}$$

Where:

TWC = Annual production of carbon-containing waste from titanium dioxide production facility (tons).

$WC_{p,n}$ = Production of carbon-containing waste in month n from chloride process line p (tons).

p = Process line.

m = Total number of process lines.

n = Number of month.

(c) If GHG emissions from a chloride process line are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process CO_2 emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

§ 98.314 Monitoring and QA/QC requirements.

(a) You must measure your consumption of calcined petroleum coke using plant instruments used for accounting purposes including direct measurement weighing the petroleum coke fed into your process (by belt scales or a similar device) or through the use of purchase records.

(b) You must document the procedures used to ensure the accuracy of monthly calcined petroleum coke consumption measurements.

(c) You must determine the carbon content of the calcined petroleum coke each month based on reports from the supplier. Alternatively, facilities can measure monthly carbon contents of the petroleum coke using ASTM D3176–89 (Reapproved 2002) Standard Practice for Ultimate Analysis of Coal and Coke (incorporated by reference, *see* § 98.7) and 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).

(d) For quality assurance and quality control of the supplier data, you must conduct an annual measurement of the carbon content from a representative sample of the petroleum coke consumed using ASTM D3176–89 and ASTM D5373–08.

(e) You must determine the quantity of carbon-containing waste generated from each titanium dioxide production line on a monthly basis using plant instruments used for accounting purposes including direct measurement weighing the carbon-containing waste not used during the process (by belt scales or a similar device) or through the use of sales records.

(f) You must determine the carbon contents of the carbon-containing waste from each titanium production line on an annual basis by collecting and analyzing a representative sample of the material using ASTM D3176–89 and ASTM D5373–08.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66469, Oct. 28, 2010]

§98.315 Procedures for estimating missing data.

For the petroleum coke input procedure in §98.313(b), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., carbon content values, etc.). Therefore, whenever the monitoring and quality assurance procedures in §98.315 cannot be followed, a substitute data value for the missing parameter shall be used in the calculations as specified in the paragraphs (a) through (c) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For each missing value of the monthly carbon content of calcined petroleum coke the substitute data value shall be the arithmetic average of the quality-assured values of carbon contents for the month immediately preceding and the month immediately following the missing data incident. If no quality-assured data on carbon contents are available prior to the missing data incident, the substitute data value shall be the first quality-assured value for carbon contents obtained after the missing data period.

(b) For each missing value of the monthly calcined petroleum coke consumption and/or carbon-containing waste, the substitute data value shall be the best available estimate of the monthly petroleum coke consumption based on all available process data or information used for accounting purposes (such as purchase records).

(c) For each missing value of the carbon content of carbon-containing waste, you must conduct a new analysis following the procedures in §98.314(f).

§98.316 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable for each titanium dioxide production line.

(a) If a CEMS is used to measure CO_2 emissions, then you must report the relevant information required under §98.36(e)(2)(vi) for the Tier 4 Calculation Methodology and the following information in this paragraph (a).

(1) Identification number of each process line.

(2) Annual consumption of calcined petroleum coke (tons).

(3) Annual production of titanium dioxide (tons).

(4) Annual production capacity of titanium dioxide (tons).

(5) Annual production of carbon-containing waste (tons), if applicable.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in this paragraph (b):

(1) Identification number of each process line.

(2) Annual CO_2 emissions from each chloride process line (metric tons/year).

(3) Annual consumption of calcined petroleum coke for each process line (tons).

(4) Annual production of titanium dioxide for each process line (tons).

(5) Annual production capacity of titanium dioxide for each process line (tons).

(6) Calcined petroleum coke consumption for each process line for each month (tons).

(7) Annual production of carbon-containing waste for each process line (tons), if applicable.

(8) Monthly production of titanium dioxide for each process line (tons).

(9) Monthly carbon content factor of petroleum coke (percent by weight expressed as a decimal fraction).

(10) Whether monthly carbon content of the petroleum coke is based on reports from the supplier or through self measurement using applicable ASTM standard methods.

(11) Carbon content for carbon-containing waste for each process line (percent by weight expressed as a decimal fraction).

(12) If carbon content of petroleum coke is based on self measurement, the ASTM standard methods used.

(13) Sampling analysis results of carbon content of petroleum coke as determined for QA/QC of supplier data under § 98.314(d) (percent by weight expressed as a decimal fraction).

(14) Number of separate chloride process lines located at the facility.

(15) The number of times in the reporting year that missing data procedures were followed to measure the carbon contents of petroleum coke (number of months); petroleum coke consumption (number of months); carbon-containing waste generated (number of months); and carbon contents of the carbon-containing waste (number of times during year).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66469, Oct. 28, 2010]

§ 98.317 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) and (b) of this section for each titanium dioxide production facility.

(a) If a CEMS is used to measure CO_2 emissions, then you must retain under this subpart required for the Tier 4 Calculation Methodology in § 98.37 and the information listed in this paragraph (a):

(1) Records of all calcined petroleum coke purchases.

(2) Annual operating hours for each titanium dioxide process line.

(b) If a CEMS is not used to measure CO_2 emissions, then you must retain records for the information listed in this paraghraph:

(1) Records of all calcined petroleum coke purchases (tons).

(2) Records of all analyses and calculations conducted for all reported data as listed in § 98.316(b).

(3) Sampling analysis results for carbon content of consumed calcined petroleum coke (percent by weight expressed as a decimal fraction).

(4) Sampling analysis results for the carbon content of carbon containing waste (percent by weight expressed as a decimal fraction), if applicable.

(5) Monthly production of carbon-containing waste (tons).

(6) You must document the procedures used to ensure the accuracy of the monthly petroleum coke consumption and quantity of carbon-containing waste measurement including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

(7) Annual operating hours for each titanium dioxide process line (hours).

§ 98.318 Definitions.

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

Subpart FF—Underground Coal Mines

SOURCE: 75 FR 39763, July 12, 2010, unless otherwise noted.

§ 98.320 Definition of the source category.

(a) This source category consists of active underground coal mines, and any underground mines under development that have operational pre-mining degasification systems. An underground coal mine is a mine at which coal is produced by tunneling into the earth to the coalbed, which is then mined with underground mining equipment such as cutting machines and continuous, longwall, and shortwall mining machines, and transported to the surface. Underground coal mines are categorized as active if any one of the following five conditions apply:

(1) Mine development is underway.

(2) Coal has been produced within the last 90 days.

(3) Mine personnel are present in the mine workings.

(4) Mine ventilation fans are operative.

(5) The mine is designated as an ''intermittent'' mine by the Mine Safety and Health Administration (MSHA).

(b) This source category includes the following:

(1) Each ventilation system shaft or vent hole, including both those points where mine ventilation air is emitted and those where it is sold, used onsite, or otherwise destroyed (including by ventilation air methane (VAM) oxidizers).

(2) Each degasification system well or gob gas vent hole, including degasification systems deployed before, during, or after mining operations are conducted in a mine area. This includes both those wells and vent holes where coal bed gas is emitted, and those where the gas is sold, used onsite, or otherwise destroyed (including by flaring).

(c) This source category does not include abandoned or closed mines, surface coal mines, or post-coal mining activities (*e.g.*, storage or transportation of coal).

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71966, Nov. 29, 2013]

§ 98.321 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an active underground coal mine and the facility meets the requirements of § 98.2(a)(1).

§ 98.322 GHGs to report.

(a) You must report CH_4 liberated from ventilation and degasification systems.

(b) You must report CH_4 destruction from systems where gas is sold, used onsite, or otherwise destroyed (including by VAM oxidation and by flaring).

(c) You must report net CH_4 emissions from ventilation and degasification systems.

(d) You must report under this subpart the CO_2 emissions from coal mine gas CH_4 destruction occurring at the facility, where the gas is not a fuel input for energy generation or use (*e.g.*, flaring and VAM oxidation).

(e) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the CO_2, CH_4, and N_2O emissions from each stationary fuel combustion unit by following the requirements of subpart C. Report emissions from both the combustion of collected coal mine CH_4 and any other fuels.

(f) An underground coal mine that is subject to this part because emissions from source categories described in Tables A–3, A–4 or A–5 of subpart A of this part, or from stationary combustion (subpart C of this part), is not required to report emissions under this subpart unless the coal mine liberates 36,500,000 actual cubic feet (acf) or more of methane per year from its ventilation system.

[75 FR 39763, July 12, 2010, as amended at 76 FR 73901, Nov. 29, 2011; 78 FR 71966, Nov. 29, 2013]

§ 98.323 Calculating GHG emissions.

(a) For each ventilation shaft, vent hole, or centralized point into which CH_4 from multiple shafts and/or vent holes are collected, you must calculate the quarterly CH_4 liberated from the ventilation system using Equation FF–1 of this section. You must measure CH_4 content, flow rate, temperature, pressure, and moisture content of the gas using the procedures outlined in § 98.324.

$$CH_{4V} = n * \left(V * MCF * \frac{C}{100\%} * 0.0423 * \frac{520^{o}R}{T} * \frac{P}{1\ \text{atm}} * 1{,}440 * \frac{0.454}{1{,}000} \right) \qquad \text{(Eq. FF-1)}$$

Where:

CH_{4V} = Quarterly CH_4 liberated from a ventilation monitoring point (metric tons CH_4).

V = Volumetric flow rate for the quarter (acfm) based on sampling or a flow rate meter. If a flow rate meter is used and the meter automatically corrects to standard temperature and pressure, then use scfm and replace ''520°R/T × P/1 atm'' with ''1''.

MCF = Moisture correction factor for the measurement period, volumetric basis.

= 1 when V and C are measured on a dry basis or if both are measured on a wet basis.

= 1-(f_{H2O}) when V is measured on a wet basis and C is measured on a dry basis.

= 1/[1-(f_{H2O})] when V is measured on a dry basis and C is measured on a wet basis.

(f_{H2O}) = Moisture content of the CH_4 emitted during the measurement period, volumetric basis (cubic feet water per cubic feet emitted gas).

C = CH_4 concentration of ventilation gas for the quarter (%).

n = The number of days in the quarter where active ventilation of mining operations is taking place at the monitoring point.

0.0423 = Density of CH_4 at 520 °R (60 °F) and 1 atm (lb/scf).

520 °R = 520 degrees Rankine.

T = Temperature at which flow is measured (°R) for the quarter.

P = Absolute pressure at which flow is measured (atm) for the quarter. The annual average barometric pressure from the nearest NOAA weather service station may be used as a default.

1,440 = Conversion factor (min/day).

0.454/1,000 = Conversion factor (metric ton/lb).

(1) Consistent with MSHA inspections, the quarterly periods are:

(i) January 1–March 31.

(ii) April 1–June 30.

(iii) July 1–September 30.

(iv) October 1–December 31.

(2) Values of V, C, T, P, and (f_{H2O}), if applicable, must be based on measurements taken at least once each quarter with no fewer than 6 weeks between measurements. If measurements are taken more frequently than once per quarter, then use the average value for all measurements taken. If continuous measurements are taken, then use the average value over the time period of continuous monitoring.

(3) If a facility has more than one monitoring point, the facility must calculate total CH_4 liberated from ventilation systems ($CH_{4VTotal}$) as the sum of the CH_4 from all ventilation monitoring points in the mine, as follows:

$$\mathrm{CH}_{4\mathrm{VTotal}} = \sum_{i=1}^{m} \left(CH_{4V}\right)_i \qquad \text{(Eq. FF-2)}$$

Where:

$CH_{4VTotal}$ = Total quarterly CH_4 liberated from ventilation systems (metric tons CH_4).

CH_{4V} = Quarterly CH_4 liberated from each ventilation monitoring point (metric tons CH_4).

m = Number of ventilation monitoring points.

(b) For each monitoring point in the degasification system (this could be at each degasification well and/or vent hole, or at more centralized points into which CH_4 from multiple wells and/or vent holes are collected), you must calculate the weekly CH_4 liberated from the mine using CH_4 measured weekly or more frequently (including by CEMS) according to 98.234(c), CH_4 content, flow rate, temperature, pressure, and moisture content, and Equation FF–3 of this section.

$$CH_{4D} = \sum_{i=1}^{n} \left(V_i * MCF_i * \frac{C_i}{100\%} * 0.0423 \frac{520^\circ R}{T_i} * \frac{P_i}{1\,atm} * 1{,}440 * \frac{0.454}{1{,}000} \right) \qquad \text{(Eq. FF-3)}$$

Where:

CH_{4D} = Weekly CH_4 liberated from at the monitoring point (metric tons CH_4).

V_i = Measured volumetric flow rate for the days in the week when the degasification system is in operation at that monitoring point, based on sampling or a flow rate meter (acfm). If a flow rate meter is used and the meter automatically corrects to standard temperature and pressure, then use scfm and replace ''520°R/T_i× P_i/1 atm'' with ''1''.

MCF_i = Moisture correction factor for the measurement period, volumetric basis.

= 1 when V_i and C_i are measured on a dry basis or if both are measured on a wet basis.

= 1-$(f_{H2O})_I$ when V_i is measured on a wet basis and C_i is measured on a dry basis.

= 1/[1-$(f_{H2O})_i$] when V_i is measured on a dry basis and C_i is measured on a wet basis.

(f_{H2O}) = Moisture content of the CH_4 emitted during the measurement period, volumetric basis (cubic feet water per cubic feet emitted gas).

C_i = CH_4 concentration of gas for the days in the week when the degasification system is in operation at that monitoring point (%).

n = The number of days in the week that the system is operational at that measurement point.

0.0423 = Density of CH_4 at 520 °R (60 °F) and 1 atm (lb/scf).

520 °R = 520 degrees Rankine.

T_i = Temperature at which flow is measured (°R).

P_i = Absolute pressure at which flow is measured (atm).

1,440 = Conversion factor (minutes/day).

0.454/1,000 = Conversion factor (metric ton/lb).

(1) Values for V, C, T, P, and (f_{H2O}), if applicable, must be based on measurements taken at least once each calendar week with at least 3 days between measurements. If measurements are taken more frequently than once per week, then use the average value for all measurements taken that week. If continuous measurements are taken, then use the average values over the time period of continuous monitoring when the continuous monitoring equipment is properly functioning.

(2) Quarterly total CH_4 liberated from degasification systems for the mine should be determined as the sum of CH_4 liberated determined at each of the monitoring points in the mine, summed over the number of weeks in the quarter, as follows:

$$\mathrm{CH}_{4\mathrm{DTotal}} = \sum_{i=1}^{m}\sum_{j=1}^{w}(CH_{4\mathrm{D}})_{i,j} \qquad \text{(Eq. FF-4)}$$

Where:

$CH_{4DTotal}$ = Quarterly CH_4 liberated from all degasification monitoring points (metric tons CH_4).

$(CH_{4D})_{i,j}$ = Weekly CH_4 liberated from a degasification monitoring point (metric tons CH_4).

m = Number of monitoring points.

w = Number of weeks in the quarter during which the degasification system is operated.

(c) If gas from a degasification system or ventilation system is sold, used onsite, or otherwise destroyed (including by flaring or VAM oxidation), you must calculate the quarterly CH_4 destroyed for each destruction device and each point of offsite transport to a destruction device, using Equation FF–5 of this section. You must measure CH_4 content and flow rate according to the provisions in § 98.324, and calculate the methane routed to the destruction device (CH_4) using either Equation FF–1 or Equation FF–4 of this section, as applicable.

$$\mathrm{CH}_{4\mathrm{Destroyed}} = \mathrm{CH}_4 \times \mathrm{DE} \qquad \text{(Eq. FF-5)}$$

Where:

$CH_{4Destroyed}$ = Quarterly CH_4 destroyed (metric tons).

CH_4 = Quarterly CH_4 routed to the destruction device or offsite transfer point (metric tons).

DE = Destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use DE = 1.

(1) Calculate total CH_4 destroyed as the sum of the methane destroyed at all destruction devices (onsite and offsite), using Equation FF–6 of this section.

$$CH_{4\,Destroyed\ Total} = \sum_{i=1}^{d}\left(CH_{4\,Destroyed}\right)_i \qquad \text{(Eq. FF-6)}$$

Where:

$CH_{4DestroyedTotal}$ = Quarterly total CH_4 destroyed at the mine (metric tons CH_4).

$CH_{4Destroyed}$ = Quarterly CH_4 destroyed from each destruction device or offsite transfer point.
d = Number of onsite destruction devices and points of offsite transport.

(2) [Reserved]

(d) You must calculate the quarterly measured net CH_4 emissions to the atmosphere using Equation FF–7 of this section.

$$CH_4 \text{ emitted (net)} = CH_{4VTotal} + CH_{4DTotal} - CH_{4destroyedTotal} \qquad \text{(Eq. FF-7)}$$

Where:
CH_4 emitted (net)= Quarterly CH_4 emissions from the mine (metric tons).
$CH_{4VTotal}$ = Quarterly sum of the CH_4 liberated from all mine ventilation monitoring points (CH_{4V}), calculated using Equation FF–2 of this section (metric tons).
$CH_{4DTotal}$ = Quarterly sum of the CH_4 liberated from all mine degasification monitoring points (CH_{4D}), calculated using Equation FF–4 of this section (metric tons).
$CH_{4DestroyedTotal}$ = Quarterly sum of the measured CH_4 destroyed from all mine ventilation and degasification systems, calculated using Equation FF–6 of this section (metric tons).

(e) For the methane collected from degasification and/or ventilation systems that is destroyed on site and is not a fuel input for energy generation or use (those emissions are monitored and reported under Subpart C of this part), you must estimate the CO_2 emissions using Equation FF–8 of this section.

$$CO_2 = CH_{4Destroyedonsite} * 44/16 \qquad \text{(Eq. FF-8)}$$

Where:
CO_2 = Total quarterly CO_2 emissions from CH_4 destruction (metric tons).
$CH_{4Destroyedonsite}$ = Quarterly sum of the CH_4 destroyed, calculated as the sum of CH_4 destroyed for each onsite, non-energy use, as calculated individually in Equation FF–5 of this section (metric tons).
44/16 = Ratio of molecular weights of CO_2 to CH_4.

[75 FR 39763, July 12, 2010, as amended at 76 FR 73901, Nov. 29, 2011; 78 FR 71967, Nov. 29, 2013]

§ 98.324 Monitoring and QA/QC requirements.

(a) For calendar year 2011 monitoring, the facility may submit a request to the Administrator to use one or more best available monitoring methods as listed in § 98.3(d)(1)(i) through (iv). The request must be submitted no later than October 12, 2010 and must contain the information in § 98.3(d)(2)(ii). To obtain approval, the request must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2011. The use of best available monitoring methods will not be approved beyond December 31, 2011.

(b) For CH_4 liberated from ventilation systems, determine whether CH_4 will be monitored from each ventilation shaft and vent hole, from a centralized monitoring point, or from a combination of the two options. Operators are allowed flexibility for aggregating emissions from more than one ventilation point, as long as emissions from all are addressed, and the methodology for calculating total emissions documented. Monitor by one of the following options:

(1) Collect quarterly or more frequent grab samples (with no fewer than 6 weeks between measurements) for methane concentration and make quarterly measurements of flow rate, temperature, pressure, and moisture content, if applicable. The sampling and measurements must be made at the same locations as Mine Safety and Health Administration (MSHA) inspection samples are taken, and should be taken when the mine is operating

under normal conditions. You must follow MSHA sampling procedures as set forth in the MSHA Handbook entitled, General Coal Mine Inspection Procedures and Inspection Tracking System Handbook Number: PH–08–V–1, January 1, 2008 (incorporated by reference, see §98.7). You must record the date of sampling, flow, temperature, pressure, and moisture measurements, the methane concentration (percent), the bottle number of samples collected, and the location of the measurement or collection.

(2) Obtain results of the quarterly (or more frequent) testing performed by MSHA for the methane flowrate. At the same location and within seven days of the MSHA sampling, make measurements of temperature and pressure using the same procedures specified in paragraph (b)(1) of this section. The annual average barometric pressure from the nearest National Oceanic and Atmospheric Administration (NOAA) weather service station may be used as a default for pressure. If the MSHA data for methane flow is provided in the units of actual cubic feet of methane per day, the methane flow data is inserted into Equation FF–1 of this section in place of the value for V and the variables MCF, C/100%, and 1440 are removed from the equation.

(3) Monitor emissions through the use of one or more continuous emission monitoring systems (CEMS). If operators use CEMS as the basis for emissions reporting, they must provide documentation on the process for using data obtained from their CEMS to estimate emissions from their mine ventilation systems.

(c) For CH_4 liberated at degasification systems, determine whether CH_4 will be monitored from each well and gob gas vent hole, from a centralized monitoring point, or from a combination of the two options. Operators are allowed flexibility for aggregating emissions from more than one well or gob gas vent hole, as long as emissions from all are addressed, and the methodology for calculating total emissions is documented. Monitor both gas volume and methane concentration by one of the following two options:

(1) Monitor emissions through the use of one or more continuous emissions monitoring systems (CEMS). If operators use CEMS as the basis for emissions reporting, they must provide documentation on the process for using data obtained from their CEMS to estimate emissions from their mine ventilation systems.

(2) Collect weekly (once each calendar week, with at least three days between measurements) or more frequent samples, for all degasification wells and gob gas vent holes. Determine weekly or more frequent flow rates, methane concentration, temperature, and pressure from these degasification wells and gob gas vent holes. Methane composition should be determined either by submitting samples to a lab for analysis, or from the use of methanometers at the degasification monitoring site. Follow the sampling protocols for sampling of methane emissions from ventilation shafts, as described in §98.324(b)(1). You must record the date of sampling, flow, temperature, pressure, and moisture measurements, the methane concentration (percent), the bottle number of samples collected, and the location of the measurement or collection.

(3) If the CH_4 concentration is determined on a dry basis and flow is determined on a wet basis or CH_4 concentration is determined on a wet basis and flow is determined on a dry basis, and the flow meter does not automatically correct for moisture content, determine the moisture content in the gas in a location near or representative of the location of:

(i) The gas flow meter at least once each calendar week; if measuring with CEMS. If only one measurement is made each calendar week, there must be at least three days between measurements; and

(ii) The grab sample, if using grab samples, at the time of the sample.

(d) Monitoring must adhere to one of the methods specified in paragraphs (d)(1) through (d)(2) of this section.

(1) ASTM D1945–03, Standard Test Method for Analysis of Natural Gas by Gas Chromatography; ASTM D1946–90 (Reapproved 2006), Standard Practice for Analysis of Reformed Gas by Gas

Chromatography; ASTM D4891–89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion; or ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see § 98.7).

(2) As an alternative to the gas chromatography methods provided in paragraph (d)(1) of this section, you may use gaseous organic concentration analyzers and a correction factor to calculate the CH_4 concentration following the requirements in paragraphs (d)(2)(i) through (d)(2)(iii) of this section.

(i) Use Method 25A or 25B at 40 CFR part 60, appendix A–7 to determine gaseous organic concentration as required in § 98.323 and in paragraphs (b) and (c) of this section. You must calibrate the instrument with CH_4 and determine the total gaseous organic concentration as carbon (or as CH_4; K=1 in Equation 25A–1 of Method 25A at 40 CFR part 60, appendix A–7).

(ii) Determine a correction factor that will be used with the gaseous organic concentrations measured in paragraph (i) of this section. The correction factor must be determined at the routine sampling location no less frequently than once a reporting year following the requirements in paragraphs (d)(2)(ii)(A) through (d)(2)(ii)(C) of this section.

(A) Take a minimum of three grab samples of the gas with a minimum of 20 minutes between samples and determine the methane composition of the gas using one of the methods specified in paragraph (d)(1) of this section.

(B) As soon as practical after each grab sample is collected and prior to the collection of a subsequent grab sample, determine the gaseous organic concentration of the gas using either Method 25A or 25B at 40 CFR part 60, appendix A–7 as specified in paragraph (d)(2)(i) of this section.

(C) Determine the arithmetic average methane concentration and the arithmetic average gaseous organic concentration of the samples analyzed according to paragraphs (d)(2)(ii)(A) and (d)(2)(ii)(B) of this section, respectively, and calculate the non-methane organic carbon correction factor as the ratio of the average methane concentration to the average total gaseous organic concentration. If the ratio exceeds 1, use 1 for the correction factor.

(iii) Calculate the CH_4 concentration as specified in Equation FF–9 of this section:

$$C_{CH4} = f_{NMOC} \times C_{TGOC} \quad \text{(Eq. FF-9)}$$

Where:

C_{CH4} = Methane (CH_4) concentration in the gas (volume %) for use in Equations FF–1 and FF–3 of this subpart.

f_{NMOC} = Correction factor from the most recent determination of the correction factor as specified in paragraph (d)(2)(ii) of this section (unitless).

C_{TGOC} = Gaseous organic carbon concentration measured using Method 25A or 25B at 40 CFR part 60, appendix A–7 during routine monitoring of the gas (volume %).

(e) All flow meters and gas composition monitors that are used to provide data for the GHG emissions calculations shall be calibrated prior to the first reporting year, using the applicable methods specified in paragraphs (d), and (e)(1) through (e)(7) of this section. Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Flow meters and gas composition monitors shall be recalibrated either at the minimum frequency specified by the manufacturer or annually. The operator shall operate, maintain, and calibrate a gas composition monitor capable of measuring the concentration of CH_4 in the gas using one of the methods specified in paragraph (d) of this section. The operator shall operate, maintain, and calibrate the flow meter using any of the following test methods or follow the procedures specified by the flow meter manufacturer. Flow meters must meet the accuracy requirements in § 98.3(i).

(1) ASME MFC–3M–2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, *see* § 98.7).

(2) ASME MFC–4M–1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters (incorporated by reference, *see* § 98.7).

(3) ASME MFC–6M–1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, *see* § 98.7).

(4) ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, *see* § 98.7).

(5) ASME MFC–11M–2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters (incorporated by reference, *see* § 98.7).

(6) ASME MFC–14M–2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, *see* § 98.7).

(7) ASME MFC–18M–2001 Measurement of Fluid Flow using Variable Area Meters (incorporated by reference, *see* § 98.7).

(f) For CH_4 destruction, CH_4 must be monitored at each onsite destruction device and each point of offsite transport for combustion using continuous monitors of gas routed to the device or point of offsite transport.

(g) All temperature, pressure, and moisture content monitors must be operated and calibrated using the procedures and frequencies specified by the manufacturer.

(h) If applicable, the owner or operator shall document the procedures used to ensure the accuracy of gas flow rate, gas composition, temperature, pressure, and moisture content measurements. These procedures include, but are not limited to, calibration of flow meters, and other measurement devices. The estimated accuracy of measurements, and the technical basis for the estimated accuracy shall be recorded.

[75 FR 39763, July 12, 2010, as amended at 76 FR 73901, Nov. 29, 2011; 78 FR 71967, Nov. 29, 2013]

§ 98.325 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (*e.g.*, if a meter 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, in accordance with paragraph (b) of this section.

(b) For each missing value of CH_4 concentration, flow rate, temperature, pressure, and moisture content for ventilation and degasification systems, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. 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.

[75 FR 39763, July 12, 2010, as amended at 76 FR 73903, Nov. 29, 2011]

§ 98.326 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each mine:

(a) Quarterly CH_4 liberated from each ventilation monitoring point, (metric tons CH_4).

(b) Weekly CH_4 liberated from each degasification system monitoring point (metric tons CH_4).

(c) Quarterly CH_4 destruction at each ventilation and degasification system destruction device or point of offsite transport (metric tons CH_4).

(d) Quarterly CH_4 emissions (net) from all ventilation and degasification systems (metric tons CH_4).

(e) Quarterly CO_2 emissions from onsite destruction of coal mine gas CH_4, where the gas is not a fuel input for energy generation or use (*e.g.*, flaring) (metric tons CO_2).

(f) Quarterly volumetric flow rate for each ventilation monitoring point and units of measure (scfm or acfm), date and location of each measurement, and method of measurement (quarterly sampling or continuous monitoring), used in Equation FF–1 of this subpart.

(g) Quarterly CH_4 concentration for each ventilation monitoring point, dates and locations of each measurement and method of measurement (sampling or continuous monitoring).

(h) Weekly volumetric flow rate used to calculate CH_4 liberated from degasification systems and units of measure (acfm or scfm), and method of measurement (sampling or continuous monitoring), used in Equation FF–3 of this subpart.

(i) Quarterly CH_4 concentration (%) used to calculate CH_4 liberated from degasification systems and if the data is based on CEMS or weekly sampling.

(j) Weekly volumetric flow rate used to calculate CH_4 destruction for each destruction device and each point of offsite transport, and units of measure (acfm or scfm).

(k) Weekly CH_4 concentration (%) used to calculate CH_4 flow to each destruction device and each point of offsite transport (C).

(l) Dates in quarterly reporting period where active ventilation of mining operations is taking place.

(m) Dates in quarterly reporting period where degasification of mining operations is taking place.

(n) Dates in quarterly reporting period when continuous monitoring equipment is not properly functioning, if applicable.

(o) Temperatures (°R), pressure (atm), moisture content, and the moisture correction factor (if applicable) used in Equation FF–1 and FF–3 of this subpart; and the gaseous organic concentration correction factor, if Equation FF–9 was required.

(p) For each destruction device, a description of the device, including an indication of whether destruction occurs at the coal mine or off-site. If destruction occurs at the mine, also report an indication of whether a back-up destruction device is present at the mine, the annual operating hours for the primary destruction device, the annual operating hours for the back-up destruction device (if present), and the destruction efficiencies assumed (percent).

(q) A description of the gas collection system (manufacturer, capacity, and number of wells) the surface area of the gas collection system (square meters), and the annual operating hours of the gas collection system.

(r) Identification information and description for each well, shaft, and vent hole, including paragraphs (r)(1) through (r)(3) of this section:

(1) Indication of whether the well, shaft, or vent hole is monitored individually, or as part of a centralized monitoring point. Note which method (sampling or continuous monitoring) was used.

(2) Start date and close date of each well, shaft, and vent hole.

(3) Number of days the well, shaft, or vent hole was in operation during the reporting year.

(s) For each centralized monitoring point, identification of the wells and shafts included in the point. Note which method (sampling or continuous monitoring) was used.

(t) Mine Safety and Health Administration (MSHA) identification for this coal mine.

[75 FR 39763, July 12, 2010, as amended at 76 FR 73903, Nov. 29, 2011; 78 FR 71967, Nov. 29, 2013]

§ 98.327 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the following records:

(a) Calibration records for all monitoring equipment, including the method or manufacturer's specification used for calibration.

(b) Records of gas sales.

(c) Logbooks of parameter measurements.

(d) Laboratory analyses of samples.

§ 98.328 Definitions.

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

Subpart GG—Zinc Production

§ 98.330 Definition of the source category.

The zinc production source category consists of zinc smelters and secondary zinc recycling facilities.

§ 98.331 Reporting threshold.

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

§ 98.332 GHGs to report.

You must report:

(a) CO_2 process emissions from each Waelz kiln and electrothermic furnace used for zinc production.

(b) CO_2, CH_4, and N_2O combustion emissions from each Waelz kiln. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

(c) CO_2, CH_4, and N_2O emissions from each stationary combustion unit other than Waelz kilns. You must report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C.

§ 98.333 Calculating GHG emissions.

You must calculate and report the annual process CO_2 emissions using the procedures specified in either paragraph (a) or (b) of this section.

(a) Calculate and report under this subpart the process or combined process and combustion CO_2 emissions by operating and maintaining a CEMS according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part (General Stationary Fuel Combustion Sources).

(b) Calculate and report under this subpart the process CO_2 emissions by following paragraphs (b)(1) and (b)(2) of this section.

(1) For each Waelz kiln or electrothermic furnace at your facility used for zinc production, you must determine the mass of carbon in each carbon-containing material, other than fuel, that is fed, charged, or otherwise introduced into each Waelz kiln and electrothermic furnace at your facility for each year and calculate annual CO_2 process emissions from each affected unit at your facility using Equation GG–1 of this section. For electrothermic furnaces, carbon containing input materials include carbon eletrodes and carbonaceous reducing agents. For Waelz kilns, carbon containing input materials include carbonaceous reducing agents. If you document that a specific material contributes less than 1 percent of the total carbon into the process, you do not have to include the material in your calculation using Equation R–1 of § 98.183.

$$E_{CO2k} = \frac{44}{12} * \frac{2000}{2205} * \left[(Zinc)_k * \left(C_{Zinc}\right)_k + (Flux)_k * (C_{Flux})_k + (Electrode)_k * \left(C_{Electrode}\right)_k + (Carbon)_k * \left(C_{carbon}\right)_k \right] \qquad \text{(Eq. GG-1)}$$

Where:

E_{CO2k} = Annual CO_2 process emissions from individual Waelz kiln or electrothermic furnace ‘‘k’’ (metric tons).

44/12 = Ratio of molecular weights, CO_2 to carbon.

2000/2205 = Conversion factor to convert tons to metric tons.

$(Zinc)_k$ = Annual mass of zinc bearing material charged to kiln or furnace ’’k’’ (tons).

$(C_{Zinc})_k$ = Carbon content of the zinc bearing material, from the annual carbon analysis for kiln or furnace ‘‘k’’ (percent by weight, expressed as a decimal fraction).

$(Flux)_k$ = Annual mass of flux materials (e.g., limestone, dolomite) charged to kiln or furnace ‘‘k’’ (tons).

$(C_{Flux})_k$ = Carbon content of the flux materials charged to kiln or furnace ‘‘k’’, from the annual carbon analysis (percent by weight, expressed as a decimal fraction).

$(Electrode)_k$ = Annual mass of carbon electrode consumed in furnace ‘‘k’’ (tons).

$(C_{Electrode})_k$ = Carbon content of the carbon electrode consumed in furnace ‘‘k’’, from the annual carbon analysis (percent by weight, expressed as a decimal fraction).

$(Carbon)_k$ = Annual mass of carbonaceous materials (e.g., coal, coke) charged to the kiln or furnace ‘‘k’’(tons).

$(C_{Carbon})_k$ Carbon content of the carbonaceous materials charged to kiln or furnace, ‘‘k’’, from the annual carbon analysis (percent by weight, expressed as a decimal fraction).

(2) You must determine the CO_2 emissions from all of the Waelz kilns or electrothermic furnaces at your facility using Equation GG–2 of this section.

$$CO_2 = \sum_{k=1}^{n} E_{CO2_k} \qquad \text{(Eq. GG-2)}$$

Where:

CO_2 = Annual combined CO_2 emissions from all Waelz kilns or electrothermic furnaces (tons).

E_{CO2_k} = Annual CO_2 emissions from each Waelz kiln or electrothermic furnace k calculated using Equation GG–1 of this section (tons).

n = Total number of Waelz kilns or electrothermic furnaces at facility used for the zinc production.

(c) If GHG emissions from a Waelz kiln or electrothermic furnace are vented through the same stack as any combustion unit or process equipment that reports CO_2 emissions using a CEMS that complies with the Tier 4 Calculation Methodology in subpart C of this part (General Stationary Fuel Combustion Sources), then the calculation methodology in paragraph (b) of this section shall not be used to calculate process emissions. The owner or operator shall report under this subpart the combined stack emissions according to the Tier 4 Calculation Methodology in § 98.33(a)(4) and all associated requirements for Tier 4 in subpart C of this part.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66470, Oct. 28, 2010]

§ 98.334 Monitoring and QA/QC requirements.

If you determine CO_2 emissions using the carbon input procedure in § 98.333(b)(1) and (b)(2), you must meet the requirements specified in paragraphs (a) and (b) of this section.

(a) Determine the mass of each solid carbon-containing input material consumed using facility instruments, procedures, or records used for accounting purposes including direct measurement weighing or through the use of purchase records same plant instruments or procedures that are used for accounting purposes (such as weigh hoppers, belt weigh feeders, weighed purchased quantities in shipments or containers, combination of bulk density and volume measurements, etc.). Record the total mass for the materials consumed each calendar month and sum the monthly mass to determine the annual mass for each input material.

(b) For each input material identified in paragraph (a) of this section, you must determine the average carbon content of the material consumed or used in the calendar year using the methods specified in either paragraph (b)(1) or (b)(2) of this section.

(1) Information provided by your material supplier.

(2) Collecting and analyzing at least three representative samples of the material using the appropriate testing method. For each carbon-containing input material identified for which the carbon content is not provided by your material supplier, the carbon content of the material must be analyzed at least annually using the appropriate standard methods (and their QA/QC procedures), which are identified in paragraphs (b)(2)(i) through (b)(2)(iii) of this section, as applicable. If you document that a specific process input or output contributes less than one percent of the total mass of carbon into or out of the process, you do not have to determine the monthly mass or annual carbon content of that input or output.

(i) Using ASTM E1941–04 Standard Test Method for Determination of Carbon in Refractory and Reactive Metals and Their Alloys (incorporated by reference, see § 98.7), analyze zinc bearing materials.

(ii) Using 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), analyze carbonaceous reducing agents and carbon electrodes.

(iii) Using ASTM C25–06 Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime (incorporated by reference, see § 98.7), analyze flux materials such as limestone or dolomite.

§ 98.335 Procedures for estimating missing data.

For the carbon input procedure in § 98.333(b), a complete record of all measured parameters used in the GHG emissions calculations is required (e.g., raw materials carbon content values, etc.). Therefore, whenever a quality-assured value of a required parameter is unavailable, a substitute data value for the missing parameter shall be used in the calculations as specified in paragraphs (a) and (b) of this section. You must document and keep records of the procedures used for all such estimates.

(a) For missing records of the carbon content of inputs for facilities that estimate emissions using the carbon input procedure in §98.333(b); 100 percent data availability is required. You must repeat the test for average carbon contents of inputs according to the procedures in §98.335(b) if data are missing.

(b) For missing records of the annual mass of carbon-containing inputs using the carbon input procedure in §98.333(b), the substitute data value must be based on the best available estimate of the mass of the input material from all available process data or information used for accounting purposes, such as purchase records.

§98.336 Data reporting requirements.

In addition to the information required by §98.3(c), each annual report must contain the information specified in paragraphs (a) or (b) of this section, as applicable, for each Waelz kiln or electrothermic furnace.

(a) If a CEMS is used to measure CO_2 emissions, then you must report under this subpart the relevant information required for the Tier 4 Calculation Methodology in §98.36 and the information listed in this paragraph (a):

(1) Annual zinc product production capacity (tons).

(2) Annual production quantity for each zinc product (tons).

(3) Annual facility production quantity for each zinc product (tons).

(4) Number of Waelz kilns at each facility used for zinc production.

(5) Number of electrothermic furnaces at each facility used for zinc production.

(b) If a CEMS is not used to measure CO_2 emissions, then you must report the information listed in this paragraph (b):

(1) Identification number and annual process CO_2 emissions from each individual Waelz kiln or electrothermic furnace (metric tons).

(2) Annual zinc product production capacity (tons).

(3) Annual production quantity for each zinc product (tons).

(4) Number of Waelz kilns at each facility used for zinc production.

(5) Number of electrothermic furnaces at each facility used for zinc production.

(6) Annual mass of each carbon-containing input material charged to each kiln or furnace (including zinc bearing material, flux materials (e.g., limestone, dolomite), carbon electrode, and other carbonaceous materials (e.g., coal, coke)) (tons).

(7) Carbon content of each carbon-containing input material charged to each kiln or furnace (including zinc bearing material, flux materials, and other carbonaceous materials) from the annual carbon analysis or from information provided by the material supplier for each kiln or furnace (percent by weight, expressed as a decimal fraction).

(8) Whether carbon content of each carbon-containing input material charged to each kiln or furnace is based on reports from the supplier or through self measurement using applicable ASTM standard method.

(9) If carbon content of each carbon-containing input material charged to each kiln or furnace is based on self measurement, the ASTM Standard Test Method used.

(10) Carbon content of the carbon electrode used in each furnace from the annual carbon analysis or from information provided by the material supplier (percent by weight, expressed as a decimal fraction).

(11) Whether carbon content of the carbon electrode used in each furnace is based on reports from the supplier or through self measurement using applicable ASTM standard method.

(12) If carbon content of carbon electrode used in each furnace is based on self measurement, the ASTM standard method used.

(13) If you use the missing data procedures in §98.335(b), you must report how the monthly mass of carbon-containing materials with missing data was determined and the number of months the missing data procedures were used.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66470, Oct. 28, 2010]

§ 98.337 Records that must be retained.

In addition to the records required by § 98.3(g), you must retain the records specified in paragraphs (a) through (b) of this section for each zinc production facility.

(a) If a CEMS is used to measure emissions, then you must retain under this subpart the records required for the Tier 4 Calculation Methodology in § 98.37 and the information listed in this paragraph (a):

(1) Monthly facility production quantity for each zinc product (tons).

(2) Annual operating hours for all Waelz kilns and electrothermic furnaces used in zinc production.

(b) If a CEMS is not used to measure emissions, you must also retain the records specified in paragraphs (b)(1) through (b)(7) of this section.

(1) Records of all analyses and calculations conducted for data reported as listed in § 98.336(b).

(2) Annual operating hours for Waelz kilns and electrothermic furnaces used in zinc production.

(3) Monthly production quantity for each zinc product (tons).

(4) Monthly mass of zinc bearing materials, flux materials (e.g., limestone, dolomite), and carbonaceous materials (e.g., coal, coke) charged to the kiln or furnace (tons).

(5) Sampling and analysis records for carbon content of zinc bearing materials, flux materials (e.g., limestone, dolomite), carbonaceous materials (e.g., coal, coke), charged to the kiln or furnace (percent by weight, expressed as a decimal fraction).

(6) Monthly mass of carbon electrode consumed in for each electrothermic furnace (tons).

(7) Sampling and analysis records for carbon content of electrode materials.

(8) You must keep records that include a detailed explanation of how company records of measurements are used to estimate the carbon input to each Waelz kiln or electrothermic furnace, as applicable to your facility, including documentation of any materials excluded from Equation GG–1 of this subpart that contribute less than 1 percent of the total carbon inputs to the process. You also must document the procedures used to ensure the accuracy of the measurements of materials fed, charged, or placed in an affected unit including, but not limited to, calibration of weighing equipment and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be provided.

§ 98.338 Definitions.

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

Subpart HH—Municipal Solid Waste Landfills

§ 98.340 Definition of the source category.

(a) This source category applies to municipal solid waste (MSW) landfills that accepted waste on or after January 1, 1980, unless all three of the following conditions apply.

(1) The MSW landfill did not receive waste on or after January 1, 2013.

(2) The MSW landfill had CH_4 generation as determined using Equation HH–5 and, if applicable, Equation HH–7 of this subpart of less than 1,190 metric tons of CH_4 in the 2013 reporting year.

(3) The owner or operator of the MSW landfill was not required to submit an annual report under any requirement of this part in any reporting year prior to 2013.

(b) This source category does not include Resource Conservation and Recovery Act (RCRA) Subtitle C or Toxic Substances Control Act (TSCA) hazardous waste landfills, construction and demolition waste landfills, or industrial waste landfills.

(c) This source category consists of the following sources at municipal solid waste (MSW) landfills: Landfills, landfill gas collection systems, and landfill gas destruction devices (including flares).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66470, Oct. 28, 2010; 78 FR 71968, Nov. 29, 2013]

§98.341 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains a MSW landfill and the facility meets the requirements of §98.2(a)(1).

§98.342 GHGs to report.

(a) You must report CH_4 generation and CH_4 emissions from landfills.

(b) You must report CH_4 destruction resulting from landfill gas collection and combustion systems.

(c) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit following the requirements of subpart C.

§98.343 Calculating GHG emissions.

(a) For all landfills subject to the reporting requirements of this subpart, calculate annual modeled CH_4 generation according to the applicable requirements in paragraphs (a)(1) through (a)(3) of this section.

(1) Calculate annual modeled CH_4 generation using Equation HH–1 of this section.

$$G_{CH4} = \sum_{x=S}^{T-1} \left\{ W_x \times MCF \times DOC \times DOC_F \times F \times \frac{16}{12} \times \left(e^{-k(T-x-1)} - e^{-k(T-x)} \right) \right\} \qquad \text{(Eq. HH-1)}$$

Where:

G_{CH4} = Modeled methane generation rate in reporting year T (metric tons CH_4).
x = Year in which waste was disposed.
S = Start year of calculation. Use the year 1960 or the opening year of the landfill, whichever is more recent.
T = Reporting year for which emissions are calculated.
W_X = Quantity of waste disposed in the landfill in year × from measurement data, tipping fee receipts, or other company records (metric tons, as received (wet weight)).
MCF = Methane correction factor (fraction). Use the default value of 1 unless there is active aeration of waste within the landfill during the reporting year. If there is active aeration of waste within the landfill during the reporting year, use either the default value of 1 or select an alternative value no less than 0.5 based on site-specific aeration parameters.
DOC = Degradable organic carbon from Table HH–1 of this subpart [fraction (metric tons C/metric ton waste)].
DOC_F = Fraction of DOC dissimilated (fraction). Use the default value of 0.5.
F = Fraction by volume of CH_4 in landfill gas from measurement data for the current reporting year, if available (fraction, dry basis, corrected to 0% oxygen); otherwise, use the default of 0.5.
k = Rate constant from Table HH–1 to this subpart (yr^{-1}). Select the most applicable k value for the majority of the past 10 years (or operating life, whichever is shorter).

(2) For years when material-specific waste quantity data are available, apply Equation HH–1 of this section for each waste quantity type and sum the CH_4 generation rates for all waste types to calculate the total modeled CH_4 generation rate for the landfill. Use the appropriate parameter values for k, DOC, MCF, DOC_F, and F shown in Table HH–1 of this subpart. The annual quantity of each type of waste disposed must be calculated as the sum of the daily quantities of waste (of that type) disposed. You may use the bulk waste parameters for a portion of your waste materials when using the material-specific modeling approach for mixed waste streams that cannot be designated to a specific material type. For years when waste composition data are not available, use the bulk waste parameter values for k and DOC in Table HH–1 to this subpart for the total quantity of waste disposed in those years.

(3) Beginning in the first emissions reporting year and for each year thereafter, if scales are in place, you must determine the annual quantity of waste (in metric tons as received, i.e., wet weight) disposed of in the landfill using paragraph (a)(3)(i) of this section for all containers and for all vehicles used to haul waste to the landfill, except for passenger cars, light duty pickup trucks, or waste loads that cannot be measured using the scales due to physical limitations (load cannot physically access or fit on the scale) and/or

operational limitations of the scale (load exceeding the limits or sensitivity range of the scale). If scales are not in place, you must use paragraph (a)(3)(ii) of this section to determine the annual quantity of waste disposed. For waste hauled to the landfill in passenger cars or light duty pickup trucks, you may use either paragraph (a)(3)(i) or paragraph (a)(3)(ii) of this section to determine the annual quantity of waste disposed. For loads that cannot be measured using the scales due to physical and/or operational limitations of the scale, you must use paragraph (a)(3)(ii) of this section or similar engineering calculations to determine the annual quantity of waste disposed. The approach used to determine the annual quantity of waste disposed of must be documented in the monitoring plan.

(i) Use direct mass measurements of each individual load received at the landfill using either of the following methods:

(A) Weigh using mass scales each vehicle or container used to haul waste as it enters the landfill or disposal area; weigh using mass scales each vehicle or container after it has off-loaded the waste; determine the quantity of waste received from the individual load as the difference in the two mass measurements; and determine the annual quantity of waste received as the sum of all waste loads received during the year. Alternatively, you may determine annual quantity of waste by summing the weights of all vehicles and containers entering the landfill and subtracting from it the sum of all the weights of vehicles and containers after they have off-loaded the waste in the landfill.

(B) Weigh using mass scales each vehicle or container used to haul waste as it enters the landfill or disposal area; determine a representative tare weight by vehicle or container type by weighing no less than 5 of each type of vehicle or container after it has off-loaded the waste; determine the quantity of waste received from the individual load as the difference between the measured weight in and the tare weight determined for that container/vehicle type; and determine the annual quantity of waste received as the sum of all waste loads received during the year.

(ii) Determine the working capacity in units of mass for each type of container or vehicle used to haul waste to the landfill (*e.g.*, using volumetric capacity and waste density measurements; direct measurement of a selected number of passenger vehicles and light duty pick-up trucks; or similar methods); record the number of loads received at the landfill by vehicle/container type; calculate the annual mass per vehicle/container type as the mass product of the number of loads of that vehicle/container multiplied by its working capacity; and calculate the annual quantity of waste received as the sum of the annual mass per vehicle/container type across all of the vehicle/container types used to haul waste to the landfill.

(4) For years prior to the first emissions reporting year, use methods in paragraph (a)(3) of this section when waste disposal quantity data are readily available. When waste disposal quantity data are not readily available, W_X shall be estimated using one of the applicable methods in paragraphs (a)(4)(i) through (a)(4)(iii) of this section. You must determine which method is most applicable to the conditions and disposal history of your facility. Historical waste disposal quantities should only be determined once, as part of the first annual report, and the same values should be used for all subsequent annual reports, supplemented by the next year's data on new waste disposal.

(i) Assume all prior years waste disposal quantities are the same as the waste quantity in the first year for which waste quantities are available.

(ii) Use the estimated population served by the landfill in each year, the values for national average per capita waste disposal rates found in Table HH–2 to this subpart, and calculate the waste quantity landfilled using Equation HH–2 of this section.

$$W_x = POP_x \times WDR_x \qquad \text{(Eq. HH-2)}$$

where:

W_X = Quantity of waste placed in the landfill in year x (metric tons, wet basis).

POP_X = Population served by the landfill in year x from city population, census data, or other estimates (capita).

WDR_X = Average per capita waste disposal rate for year x from Table HH–2 to this subpart (metric tons per capita per year, wet basis; tons/cap/yr).

(iii) Use a constant average waste disposal quantity calculated using Equation HH–3 of this section for each year the landfill was in operation (i.e., from the first year accepting waste until the last year for which waste disposal data is unavailable, inclusive).

$$W_x = \frac{LFC}{(YrData - YrOpen + 1)} \quad \text{(Eq. HH-3)}$$

where:

W_X = Quantity of waste placed in the landfill in year x (metric tons, wet basis).

LFC = Landfill capacity or, for operating landfills, capacity of the landfill used (or the total quantity of waste-in-place) at the end of the year prior to the year when waste disposal data are available from design drawings or engineering estimates (metric tons).

YrData = Year in which the landfill last received waste or, for operating landfills, the year prior to the first reporting year when waste disposal data is first available from company records, or best available data.

YrOpen = Year in which the landfill first received waste from company records or best available data. If no data are available for estimating YrOpen for a closed landfill, use 30 years as the default operating life of the landfill.

(b) For landfills with gas collection systems, calculate the quantity of CH_4 destroyed according to the requirements in paragraphs (b)(1) and (b)(2) of this section.

(1) If you continuously monitor the flow rate, CH_4 concentration, temperature, pressure, and, if necessary, moisture content of the landfill gas that is collected and routed to a destruction device (before any treatment equipment) using a monitoring meter specifically for CH_4 gas, as specified in § 98.344, you must use this monitoring system and calculate the quantity of CH_4 recovered for destruction using Equation HH–4 of this section. A fully integrated system that directly reports CH_4 content requires no other calculation than summing the results of all monitoring periods for a given year.

$$R = \sum_{n=1}^{N} \left((V)_n \times (K_{MC})_n \times \frac{(C_{CH4})_n}{100\%} \times 0.0423 \times \frac{520°R}{(T)_n} \times \frac{(P)_n}{1\,atm} \times \frac{0.454}{1{,}000} \right) \quad \text{(Eq. HH-4)}$$

where:

R = Annual quantity of recovered CH_4 (metric tons CH_4).

N = Total number of measurement periods in a year. Use daily averaging periods for a continuous monitoring system and N = 365 (or N = 366 for leap years). For monthly sampling, as provided in paragraph (b)(2) of this section, use N=12.

n = Index for measurement period.

$(V)_n$ = Cumulative volumetric flow for the measurement period in actual cubic feet (acf). If the flow rate meter automatically corrects for temperature and pressure, replace "$520°R/(T)_n \times (P)_n/1$ atm" with "1".

$(K_{MC})_n$ = Moisture correction term for the measurement period, volumetric basis, as follows: $(K_{MC})_n = 1$ when $(V)_n$ and $(C)_n$ are both measured on a dry basis or if both are measured on a wet basis; $(K_{MC})_n = [1-(f_{H_2O})_n]$ when $(V)_n$ is measured on a wet basis and $(C)_n$ is measured on a dry basis; and $(K_{MC})_n = 1/[1-(f_{H2O})_n]$ when $(V)_n$ is measured on a dry basis and $(C)_n$ is measured on a wet basis.

$(f_{H_2O})_n$ = Average moisture content of landfill gas during the measurement period, volumetric basis (cubic feet water per cubic feet landfill gas)

$(C_{CH4})_n$ = Average CH_4 concentration of landfill gas for the measurement period (volume %).

0.0423 = Density of CH_4 lb/cf at 520°R or 60 degrees Fahrenheit and 1 atm.

$(T)_n$ = Average temperature at which flow is measured for the measurement period (°R).

$(P)_n$ = Average pressure at which flow is measured for the measurement period (atm).

0.454/1,000 = Conversion factor (metric ton/lb).

(2) If you do not continuously monitor according to paragraph (b)(1) of this section, you must determine the flow rate, CH_4 concentration, temperature, pressure, and moisture content of

the landfill gas that is collected and routed to a destruction device (before any treatment equipment) according to the requirements in paragraphs (b)(2)(i) through (b)(2)(iii) of this section and calculate the quantity of CH_4 recovered for destruction using Equation HH–4 of this section.

(i) Continuously monitor gas flow rate and determine the cumulative volume of landfill gas each month and the cumulative volume of landfill gas each year that is collected and routed to a destruction device (before any treatment equipment). Under this option, the gas flow meter is not required to automatically correct for temperature, pressure, or, if necessary, moisture content. If the gas flow meter is not equipped with automatic correction for temperature, pressure, or, if necessary, moisture content, you must determine these parameters as specified in paragraph (b)(2)(iii) of this section.

(ii) Determine the CH_4 concentration in the landfill gas that is collected and routed to a destruction device (before any treatment equipment) in a location near or representative of the location of the gas flow meter at least once each calendar month; if only one measurement is made each calendar month, there must be at least fourteen days between measurements.

(iii) If the gas flow meter is not equipped with automatic correction for temperature, pressure, or, if necessary, moisture content:

(A) Determine the temperature and pressure in the landfill gas that is collected and routed to a destruction device (before any treatment equipment) in a location near or representative of the location of the gas flow meter at least once each calendar month; if only one measurement is made each calendar month, there must be at least fourteen days between measurements.

(B) If the CH_4 concentration is determined on a dry basis and flow is determined on a wet basis or CH_4 concentration is determined on a wet basis and flow is determined on a dry basis, and the flow meter does not automatically correct for moisture content, determine the moisture content in the landfill gas that is collected and routed to a destruction device (before any treatment equipment) in a location near or representative of the location of the gas flow meter at least once each calendar month; if only one measurement is made each calendar month, there must be at least fourteen days between measurements.

(c) For all landfills, calculate CH_4 generation (adjusted for oxidation in cover materials) and actual CH_4 emissions (taking into account any CH_4 recovery, and oxidation in cover materials) according to the applicable methods in paragraphs (c)(1) through (c)(3) of this section.

(1) Calculate CH_4 generation, adjusted for oxidation, from the modeled CH_4 (G_{CH_4} from Equation HH–1 of this section) using Equation HH–5 of this section.

$$MG = G_{CH4} \times (1 - OX) \qquad \text{(Eq. HH-5)}$$

Where:

MG = Methane generation, adjusted for oxidation, from the landfill in the reporting year (metric tons CH_4).

G_{CH4} = Modeled methane generation rate in reporting year from Equation HH–1 of this section (metric tons CH_4).

OX = Oxidation fraction. Use the appropriate oxidation fraction default value from Table HH–4 of this subpart.

(2) For landfills that do not have landfill gas collection systems, the CH_4 emissions are equal to the CH_4 generation (MG) calculated in Equation HH–5 of this section.

(3) For landfills with landfill gas collection systems, calculate CH_4 emissions using the methodologies specified in paragraphs (c)(3)(i) and (c)(3)(ii) of this section.

(i) Calculate CH_4 emissions from the modeled CH_4 generation and measured CH_4 recovery using Equation HH–6 of this section.

$$\text{Emissions} = \left[\left(G_{CH4} - \sum_{n-1}^{N} R_n\right) \times (1 - OX) + \sum_{n-1}^{N} \left\{R_n \times \left(1 - \left(DE_n \times f_{Dest,n}\right)\right)\right\}\right] \qquad \text{(Eq. HH-6)}$$

Where:

Emissions = Methane emissions from the landfill in the reporting year (metric tons CH_4).

G_{CH4} = Modeled methane generation rate in reporting year from Equation HH–1 of this section or the quantity of recovered CH_4 from Equation HH–4 of this section, whichever is greater (metric tons CH_4).

N = Number of landfill gas measurement locations (associated with a destruction device or gas sent off-site). If a single monitoring location is used to monitor volumetric flow and CH_4 concentration of the recovered gas sent to one or multiple destruction devices, then N=1.

R_n = Quantity of recovered CH_4 from Equation HH–4 of this section for the nth measurement location (metric tons).

OX = Oxidation fraction. Use the appropriate oxidation fraction default value from Table HH–4 of this subpart.

DE_n = Destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99) for the nth measurement location. If the gas is transported off-site for destruction, use DE = 1. If the volumetric flow and CH_4 concentration of the recovered gas is measured at a single location providing landfill gas to multiple destruction devices (including some gas destroyed on-site and some gas sent off-site for destruction), calculate DE_n as the arithmetic average of the DE values determined for each destruction device associated with that measurement location.

$f_{Dest,n}$ = Fraction of hours the destruction device associated with the nth measurement location was operating during active gas flow calculated as the annual operating hours for the destruction device divided by the annual hours flow was sent to the destruction device as measured at the nth measurement location. If the gas is transported off-site for destruction, use $f_{Dest,n}$= 1. If the volumetric flow and CH_4 concentration of the recovered gas is measured at a single location providing landfill gas to multiple destruction devices (including some gas destroyed on-site and some gas sent off-site for destruction), calculate $f_{Dest,n}$ as the arithmetic average of the f_{Dest} values determined for each destruction device associated with that measurement location.

(ii) Calculate CH_4 generation and CH_4 emissions using measured CH_4 recovery and estimated gas collection efficiency and Equations HH–7 and HH–8 of this section.

$$MG = \frac{1}{CE} \sum_{n=1}^{N} \left[\frac{R_n}{f_{Rec,n}} \right] \times (1 - OX) \qquad \text{(Eq. HH-7)}$$

$$Emissions = \left[\left(\frac{1}{CE} \left\{ \sum_{n-1}^{N} \left[\frac{R_n}{f_{Rec,n}} \right] \right\} - \sum_{n-1}^{N} R_n \right) \times (1 - OX) + \sum_{n=1}^{N} \left\{ R_n \times \left(1 - \left(DE_n \times f_{Dest,n}\right)\right) \right\} \right] \qquad \text{(Eq. HH-8)}$$

Where:

MG = Methane generation, adjusted for oxidation, from the landfill in the reporting year (metric tons CH_4).

Emissions = Methane emissions from the landfill in the reporting year (metric tons CH_4).

N = Number of landfill gas measurement locations (associated with a destruction device or gas sent off-site). If a single monitoring location is used to monitor volumetric flow and CH_4 concentration of the recovered gas sent to one or multiple destruction devices, then N=1.

R_n = Quantity of recovered CH_4 from Equation HH–4 of this section for the nth measurement location (metric tons CH_4).

CE = Collection efficiency estimated at landfill, taking into account system coverage, operation, and cover system materials from Table HH–3 of this subpart. If area by soil cover type information is not available, use default value of 0.75 (CE4 in table HH–3 of this subpart) for all areas under active influence of the collection system.

$f_{Rec,n}$ = Fraction of hours the recovery system associated with the nth measurement location was operating (annual operating hours/8760 hours per year or annual operating hours/8784 hours per year for a leap year).

OX = Oxidation fraction. Use appropriate oxidation fraction default value from Table HH–4 of this subpart.

DE_n = Destruction efficiency, (lesser of manufacturer's specified destruction efficiency and 0.99) for the nth measurement location. If the gas is transported off-site for destruction, use DE = 1. If the volumetric flow and CH_4 concentration of the recovered gas is measured at a single location providing landfill gas to multiple destruction devices (including some gas destroyed on-site and some gas sent off-site for destruction), calculate DE_n as the arithmetic average of the DE values determined for each destruction device associated with that measurement location.

$f_{Dest,n}$ = Fraction of hours the destruction device associated with the n^{th} measurement location was operating during active gas flow calculated as the annual operating hours for the destruction device divided by the annual hours flow was sent to the destruction device as measured at the n^{th} measurement location. If the gas is transported off-site for destruction, use $f_{Dest,n}$= 1. If the volumetric flow and CH_4 concentration of the recovered gas is measured at a single location providing landfill gas to multiple destruction devices (including some gas destroyed on-site and some gas sent off-site for destruction), calculate $f_{Dest,n}$ as the arithmetic average of the f_{Dest} values determined for each destruction device associated with that measurement location.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66470, Oct. 28, 2010; 78 FR 71968, Nov. 29, 2013]

§ 98.344 Monitoring and QA/QC requirements.

(a) Mass measurement equipment used to determine the quantity of waste landfilled on or after January 1, 2010 must meet the requirements for 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).

(b) For landfills with gas collection systems, operate, maintain, and calibrate a gas composition monitor capable of measuring the concentration of CH_4 in the recovered landfill gas using one of the methods specified in paragraphs (b)(1) through (b)(6) of this section or as specified by the manufacturer. Gas composition monitors shall be calibrated prior to the first reporting year and recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent, or whenever the error in the midrange calibration check exceeds ±10 percent.

(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 Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

(5) UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, see § 98.7).

(6) As an alternative to the gas chromatography methods provided in paragraphs (b)(1) through (b)(5) of this section, you may use total gaseous organic concentration analyzers and calculate the methane concentration following the requirements in paragraphs (b)(6)(i) through (b)(6)(iii) of this section.

(i) Use Method 25A or 25B at 40 CFR part 60, appendix A–7 to determine total gaseous organic concentration. You must calibrate the instrument with methane and determine the total gaseous organic concentration as carbon (or as methane; K=1 in Equation 25A–1 of Method 25A at 40 CFR part 60, appendix A–7).

(ii) Determine a non-methane organic carbon correction factor at the routine sampling location no less frequently than once a reporting year following the requirements in paragraphs (b)(6)(ii)(A) through (b)(6)(ii)(C) of this section.

(A) Take a minimum of three grab samples of the landfill gas with a minimum of 20 minutes between samples and determine the methane composition of the landfill gas using one of the methods specified in paragraphs (b)(1) through (b)(5) of this section.

(B) As soon as practical after each grab sample is collected and prior to the collection of a subsequent grab sample, determine the total gaseous organic concentration of the landfill gas using either Method 25A or 25B at 40 CFR part 60, appendix A–7 as specified in paragraph (b)(6)(i) of this section.

(C) Determine the arithmetic average methane concentration and the arithmetic average total gaseous organic concentration of the samples analyzed according to paragraphs (b)(6)(ii)(A) and (b)(6)(ii)(B) of this section, respectively, and calculate the non-methane organic carbon correction factor as the ratio of the average methane concentration to the average total gaseous organic concentration. If the ratio exceeds 1, use 1 for the non-methane organic carbon correction factor.

(iii) Calculate the methane concentration as specified in Equation HH–9 of this section.

$$C_{CH4} = f_{NMOC} \times C_{TGOC} \qquad \text{(Eq. HH-9)}$$

Where:

C_{CH4} = Methane concentration in the landfill gas (volume %) for use in Equation HH–4 of this subpart.

f_{NMOC} = Non-methane organic carbon correction factor from the most recent determination of the non-methane organic carbon correction factor as specified in paragraph (b)(6)(ii) of this section (unitless).

C_{TGOC} = Total gaseous organic carbon concentration measured using Method 25A or 25B at 40 CFR part 60, appendix A–7 during routine monitoring of the landfill gas (volume %).

(c) For landfills with gas collection systems, install, operate, maintain, and calibrate a gas flow meter capable of measuring the volumetric flow rate of the recovered landfill gas using one of the methods specified in paragraphs (c)(1) through (c)(8) of this section or as specified by the manufacturer. Each gas flow meter shall be recalibrated either biennially (every 2 years) or at the minimum frequency specified by the manufacturer. Except as provided in § 98.343(b)(2)(i), each gas flow meter must be capable of correcting for the temperature and pressure and, if necessary, moisture content.

(1) ASME MFC–3M–2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, *see* § 98.7).

(2) ASME MFC–4M–1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters (incorporated by reference, *see* § 98.7).

(3) ASME MFC–6M–1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, *see* § 98.7).

(4) ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, *see* § 98.7).

(5) ASME MFC–11M–2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters (incorporated by reference, *see* § 98.7). The mass flow must be corrected to volumetric flow based on the measured temperature, pressure, and gas composition.

(6) ASME MFC–14M–2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, *see* § 98.7).

(7) ASME MFC–18M–2001 Measurement of Fluid Flow using Variable Area Meters (incorporated by reference, *see* § 98.7).

(8) Method 2A or 2D at 40 CFR part 60, appendix A–1.

(d) All temperature, pressure, and if necessary, moisture content monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

(e) For landfills electing to measure the fraction by volume of CH_4 in landfill gas (F), follow the requirements in paragraphs (e)(1) and (2) of this section. (1) Use a gas composition monitor capable of measuring the concentration of CH_4 on a dry basis that is properly operated, calibrated, and maintained according to the requirements specified in paragraph (b) of this section. You must either use a gas composition monitor that is also capable of measuring the O_2 concentration correcting for excess (infiltration) air or you must operate, maintain, and calibrate a second monitor capable of measuring the O_2 concentration on a dry basis according to the manufacturer's specifications.

(2) Use Equation HH–10 of this section to correct the measured CH_4 concentration to 0% oxygen. If multiple CH_4 concentration measurements are made during the reporting year, determine F separately for each measurement made during the reporting year, and use the results to determine the arithmetic average value of F for use in Equation HH–1 of this part.

$$F = \left(\frac{C_{CH4}}{100\%}\right) \times \left[20.9_c \big/ \left(20.9 - \%O_2\right) \right] \qquad \text{(Eq. HH-10)}$$

Where:

F = Fraction by volume of CH_4 in landfill gas (fraction, dry basis, corrected to 0% oxygen).

C_{CH4} = Measured CH_4 concentration in landfill gas (volume %, dry basis).

20.9_c = Defined O_2 correction basis, (volume %, dry basis).

20.9 = O_2 concentration in air (volume %, dry basis).

$\%O_2$ = Measured O_2 concentration in landfill gas (volume %, dry basis).

(f) The owner or operator shall document the procedures used to ensure the accuracy of the estimates of disposal quantities and, if applicable, gas flow rate, gas composition, temperature, pressure, and moisture content measurements. These procedures include, but are not limited to, calibration of weighing equipment, fuel flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices, and the technical basis for these estimates shall be recorded.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66472, Oct. 28, 2010; 78 FR 71969, Nov. 29, 2013]

§ 98.345 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter 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, according to the requirements in paragraphs (a) through (c) of this section.

(a) For each missing value of the CH_4 content, the substitute data value shall be 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.

(b) For missing gas flow rates, the substitute data value shall be 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 daily waste disposal quantity data for disposal in the reporting year, the substitute value shall be the average daily waste disposal quantity for that day of the week as measured on the week before and week after the missing daily data.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71970, Nov. 29, 2013]

§ 98.346 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each landfill.

(a) A classification of the landfill as ‘‘open’’ (actively received waste in the reporting year) or ‘‘closed’’ (no longer receiving waste), the year in which the landfill first started accepting waste for disposal, the last year the landfill accepted waste (for open landfills, enter the estimated year of landfill closure), the capacity (in metric tons) of the landfill, an indication of whether leachate recirculation is used during the reporting year and its typical frequency of use over the past 10 years (e.g., used several times a year for the past 10 years, used at least once a year for the past 10 years, used occasionally but not every year over the past 10 years, not used), an indication as to whether scales are present at the landfill, and the waste disposal quantity for each year of landfilling required to be included when using Equation HH–1 of this subpart (in metric tons, wet weight).

(b) Method for estimating reporting year and historical waste disposal quantities, reason for its selection, and the range of years it is applied. For years when waste quantity data are determined using the methods in § 98.343(a)(3), report separately the quantity of waste determined using the methods in § 98.343(a)(3)(i) and the quantity of waste determined using the methods in § 98.343(a)(3)(ii). For historical waste disposal quantities that were not determined using the methods in § 98.343(a)(3), provide the population served by the landfill for each year the Equation HH–2 of this subpart is applied, if applicable, or, for open landfills using Equation HH–3 of this subpart, provide the value of landfill capacity (LFC) used in the calculation.

(c) Waste composition for each year required for Equation HH–1 of this subpart, in percentage by weight, for each waste category listed in Table HH–1 to this subpart that is used in Equation HH–1 of this subpart to calculate the annual modeled CH_4 generation.

(d) For each waste type used to calculate CH_4 generation using Equation HH–1 of this subpart, you must report:

(1) Degradable organic carbon (DOC) and fraction of DOC dissimilated (DOC_F) values used in the calculations.

(2) Decay rate (k) value used in the calculations.

(e) Fraction of CH_4 in landfill gas (F), an indication of whether the fraction of CH_4 was determined based on measured values or the default value, and the methane correction factor (MCF) used in the calculations. If an MCF other than the default of 1 is used, provide an indication of whether active aeration of the waste in the landfill was conducted during the reporting year, a description of the aeration system, including aeration blower capacity, the fraction of the landfill containing waste affected by aeration, the total number of hours during the year the aeration blower was operated, and other factors used as a basis for the selected MCF value.

(f) The surface area of the landfill containing waste (in square meters), identification of the type of cover material used (as either organic cover, clay cover, sand cover, or other soil mixtures). If multiple cover types are used, the surface area associated with each cover type.

(g) The modeled annual methane generation rate for the reporting year (metric tons CH_4) calculated using Equation HH–1 of this subpart.

(h) For landfills without gas collection systems, the annual methane emissions (i.e., the methane generation, adjusted for oxidation, calculated using Equation HH–5 of this subpart), reported in metric tons CH_4, the oxidation fraction used in the calculation, and an indication of whether passive vents and/or passive flares (vents or flares that are not considered part of the gas collection system as defined in § 98.6) are present at this landfill.

(i) For landfills with gas collection systems, you must report:

(1) Total volumetric flow of landfill gas collected for destruction for the reporting year (cubic feet at 520 °R or 60 degrees Fahrenheit and 1 atm).

(2) Annual average CH_4 concentration of landfill gas collected for destruction (percent by volume).

(3) Monthly average temperature and pressure for each month at which flow is measured for landfill gas collected for destruction, or statement that temperature and/or pressure is incorporated into internal calculations run by the monitoring equipment.

(4) An indication as to whether flow was measured on a wet or dry basis, an indication as to whether CH_4 concentration was measured on a wet or dry basis, and if required for Equation HH–4 of this subpart, monthly average moisture content for each month at which flow is measured for landfill gas collected for destruction.

(5) An indication of whether destruction occurs at the landfill facility, off-site, or both. If destruction occurs at the landfill facility, also report for each measurement location the number of destruction devices associated with

that measurement location and the annual operating hours and the destruction efficiency (percent) for each destruction device associated with that measurement location.

(6) Annual quantity of recovered CH_4 (metric tons CH_4) calculated using Equation HH–4 of this subpart for each measurement location.

(7) A description of the gas collection system (manufacturer, capacity, and number of wells), the surface area (square meters) and estimated waste depth (meters) for each area specified in Table HH–3 to this subpart, the estimated gas collection system efficiency for landfills with this gas collection system, the annual operating hours of the gas collection system for each measurement location, and an indication of whether passive vents and/or passive flares (vents or flares that are not considered part of the gas collection system as defined in § 98.6) are present at the landfill.

(8) Methane generation corrected for oxidation calculated using Equation HH–5 of this subpart, reported in metric tons CH_4, and the oxidation fraction used in the calculation.

(9) Methane generation (G_{CH4}) value used as an input to Equation HH–6 of this subpart. Specify whether the value is modeled (G_{CH4} from HH–1 of this subpart) or measured (R from Equation HH–4 of this subpart).

(10) Methane generation corrected for oxidation calculated using Equation HH–7 of this subpart, reported in metric tons CH_4, and the oxidation fraction used in the calculation.

(11) Methane emissions calculated using Equation HH–6 of this subpart, reported in metric tons CH_4, and the oxidation fraction used in the calculation.

(12) Methane emissions calculated using Equation HH–8 of this subpart, reported in metric tons CH_4, and the oxidation fraction used in the calculation.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66472, Oct. 28, 2010; 78 FR 71970, Nov. 29, 2013]

§ 98.347 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the calibration records for all monitoring equipment, including the method or manufacturer's specification used for calibration. You must retain records of all measurements made to determine tare weights and working capacities by vehicle/container type if these are used to determine the annual waste quantities.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66473, Oct. 28, 2010]

§ 98.348 Definitions.

Except as specified in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Construction and demolition (C&D) waste landfill means a solid waste disposal facility subject to the requirements of part 257, subparts A or B of this chapter that receives construction and demolition waste and does not receive hazardous waste (defined in § 261.3 of this chapter) or industrial solid waste (defined in § 258.2 of this chapter) or municipal solid waste (as defined in § 98.6) other than residential lead-based paint waste. A C&D waste landfill typically receives any one or more of the following types of solid wastes: Roadwork material, excavated material, demolition waste, construction/renovation waste, and site clearance waste.

Destruction device means a flare, thermal oxidizer, boiler, turbine, internal combustion engine, or any other combustion unit used to destroy or oxidize methane contained in landfill gas.

Industrial waste landfill means any landfill other than a municipal solid waste landfill, a RCRA Subtitle C hazardous waste landfill, or a TSCA hazardous waste landfill, in which industrial solid waste, such a RCRA Subtitle D wastes (nonhazardous industrial solid waste, defined in § 257.2 of this chapter), commercial solid wastes, or conditionally exempt small quantity generator wastes, is placed. An industrial waste landfill includes all disposal areas at the facility.

Landfill capacity means the maximum amount of solid waste a landfill can accept. For the purposes of this subpart, for landfills that have a permit, the *landfill capacity* can be determined in terms of volume or mass in the most recent permit issued by the state, local, or Tribal agency responsible for regulating the landfill, plus any in-place waste not accounted for in the most recent permit. If the owner or operator chooses to convert from volume to mass to determine its capacity, the calculation must include a site-specific density.

Leachate recirculation means the practice of taking the leachate collected from the landfill and reapplying it to the landfill by any of one of a variety of methods, including pre-wetting of the waste, direct discharge into the working face, spraying, infiltration ponds, vertical injection wells, horizontal gravity distribution systems, and pressure distribution systems.

Solid waste has the meaning established by the Administrator pursuant to the Solid Waste Disposal Act (42 U.S.C.A. 6901 *et seq.*).

Working capacity means the maximum volume or mass of waste that is actually placed in the landfill from an individual or representative type of container (such as a tank, truck, or roll-off bin) used to convey wastes to the landfill, taking into account that the container may not be able to be 100 percent filled and/or 100 percent emptied for each load.

[75 FR 66473, Oct. 28, 2010, as amended at 78 FR 71970, Nov. 29, 2013]

TABLE HH–1 TO SUBPART HH OF PART 98—EMISSIONS FACTORS, OXIDATION FACTORS AND METHODS

Factor	Default value	Units
DOC and k values—Bulk waste option		
DOC (bulk waste)	0.20	Weight fraction, wet basis.
k (precipitation plus recirculated leachate[a] <20 inches/year)	0.02	yr^{-1}
k (precipitation plus recirculated leachate[a] 20–40 inches/year)	0.038	yr^{-1}
k (precipitation plus recirculated leachate[a] >40 inches/year)	0.057	yr^{-1}
DOC and k values—Modified bulk MSW option		
DOC (bulk MSW, excluding inerts and C&D waste)	0.31	Weight fraction, wet basis.
DOC (inerts, e.g., glass, plastics, metal, concrete)	0.00	Weight fraction, wet basis.
DOC (C&D waste)	0.08	Weight fraction, wet basis.
k (bulk MSW, excluding inerts and C&D waste)	0.02 to 0.057[b]	yr^{-1}
k (inerts, e.g., glass, plastics, metal, concrete)	0.00	yr^{-1}
k (C&D waste)	0.02 to 0.04[b]	yr^{-1}
DOC and k values—Waste composition option		
DOC (food waste)	0.15	Weight fraction, wet basis.
DOC (garden)	0.2	Weight fraction, wet basis.
DOC (paper)	0.4	Weight fraction, wet basis.
DOC (wood and straw)	0.43	Weight fraction, wet basis.
DOC (textiles)	0.24	Weight fraction, wet basis.
DOC (diapers)	0.24	Weight fraction, wet basis.
DOC (sewage sludge)	0.05	Weight fraction, wet basis.
DOC (inerts, e.g., glass, plastics, metal, cement)	0.00	Weight fraction, wet basis.
k (food waste)	0.06 to 0.185[c]	yr^{-1}
k (garden)	0.05 to 0.10[c]	yr^{-1}
k (paper)	0.04 to 0.06[c]	yr^{-1}
k (wood and straw)	0.02 to 0.03[c]	yr^{-1}
k (textiles)	0.04 to 0.06[c]	yr^{-1}
k (diapers)	0.05 to 0.10[c]	yr^{-1}
k (sewage sludge)	0.06 to 0.185[c]	yr^{-1}
k (inerts e.g., glass, plastics, metal, concrete)	0.00	yr^{-1}
Other parameters—All MSW landfills		
MCF	1.	
DOC_F	0.5.	
F	0.5.	
OX	See Table HH–4 of this subpart.	
DE	0.99.	

[a] Recirculated leachate (in inches/year) is the total volume of leachate recirculated from company records or engineering estimates divided by the area of the portion of the landfill containing waste with appropriate unit conversions. Alternatively, landfills that use leachate recirculation can elect to use the k value of 0.057 rather than calculating the recirculated leachate rate.

[b] Use the lesser value when precipitation plus recirculated leachate is less than 20 inches/year. Use the greater value when precipitation plus recirculated leachate is greater than 40 inches/year. Use the average of the range of values when precipitation plus recirculated leachate is 20 to 40 inches/year (inclusive). Alternatively, landfills that use leachate recirculation can elect to use the greater value rather than calculating the recirculated leachate rate.

[c] Use the lesser value when the potential evapotranspiration rate exceeds the mean annual precipitation rate plus recirculated leachate. Use the greater value when the potential evapotranspiration rate does not exceed the mean annual precipitation rate plus recirculated leachate. Alternatively, landfills that use leachate recirculation can elect to use the greater value rather than assessing the potential evapotranspiration rate or recirculated leachate rate.

[75 FR 66473, Oct. 28, 2010, as amended at 78 FR 71970, Nov. 29, 2013]

TABLE HH–2 TO SUBPART HH OF PART 98—U.S. PER CAPITA WASTE DISPOSAL RATES

Year	Waste per capita ton/cap/yr
1950	0.63
1951	0.63
1952	0.63
1953	0.63
1954	0.63
1955	0.63
1956	0.63
1957	0.63
1958	0.63
1959	0.63
1960	0.63
1961	0.64
1962	0.64
1963	0.65
1964	0.65
1965	0.66
1966	0.66
1967	0.67
1968	0.68
1969	0.68
1970	0.69
1971	0.69
1972	0.70
1973	0.71
1974	0.71
1975	0.72
1976	0.73
1977	0.73
1978	0.74
1979	0.75
1980	0.75
1981	0.76
1982	0.77
1983	0.77
1984	0.78
1985	0.79
1986	0.79
1987	0.80
1988	0.80
1989	0.83
1990	0.82
1991	0.76
1992	0.74
1993	0.76
1994	0.75
1995	0.70
1996	0.68
1997	0.69
1998	0.75
1999	0.75
2000	0.80
2001	0.91
2002	1.02
2003	1.02
2004	1.01
2005	0.98
2006	0.95
2007	0.95
2008	0.95
2009 and all later years	0.95

[78 FR 71971, Nov. 29, 2013]

TABLE HH–3 TO SUBPART HH OF PART 98—LANDFILL GAS COLLECTION EFFICIENCIES

Description	Landfill Gas Collection Efficiency
A1: Area with no waste in-place	Not applicable; do not use this area in the calculation.
A2: Area without active gas collection, regardless of cover type	CE2: 0%.
A3: Area with daily soil cover and active gas collection	CE3: 60%.
A4: Area with an intermediate soil cover, or a final soil cover not meeting the criteria for A5 below, and active gas collection.	CE4: 75%.
A5: Area with a final soil cover of 3 feet or thicker of clay and/or geomembrane cover system and active gas collection.	CE5: 95%.
Area weighted average collection efficiency for landfills	CEave1 = (A2*CE2 + A3*CE3 + A4*CE4 + A5*CE5) / (A2 + A3 + A4 + A5).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66474, Oct. 28, 2010]

TABLE HH–4 TO SUBPART HH OF PART 98—LANDFILL METHANE OXIDATION FRACTIONS

Under these conditions:	Use this landfill methane oxidation fraction:
I. For all reporting years prior to the 2013 reporting year	
C1: For all landfills regardless of cover type or methane flux	0.10
II. For the 2013 reporting year and all subsequent years	
C2: For landfills that have a geomembrane (synthetic) cover with less than 12 inches of cover soil for the majority of the landfill area containing waste	0.0
C3: For landfills that do not meet the conditions in C2 above, and for which you elect not to determine methane flux	0.10
C4: For landfills that do not meet the conditions in C2 above and that do not have a soil cover of at least 24 inches for a majority of the landfill area containing waste	0.10
C5: For landfills that have a soil cover of at least 24 inches for a majority of the landfill area containing waste and for which the methane flux rate is less than 10 grams per square meter per day ($g/m^2/d$)	0.35
C6: For landfills that have a soil cover of at least 24 inches for a majority of the landfill area containing waste and for which the methane flux rate is 10 to 70 $g/m^2/d$	0.25
C7: For landfills that have a soil cover of at least 24 inches for a majority of the landfill area containing waste and for which the methane flux rate is greater than 70 $g/m^2/d$	0.10

[a] Methane flux rate (in grams per square meter per day; $g/m^2/d$) is the mass flow rate of methane per unit area at the bottom of the surface soil prior to any oxidation and is calculated as follows:

For Equation HH-5 of this subpart, or for Equation TT-6 of subpart TT of this part,

$$MF = K \times G_{CH4} / SArea$$

For Equation HH-6 of this subpart,

$$MF = K \times \left(G_{CH4} - \sum_{n-1}^{N} R_n \right) \Big/ SArea$$

For Equations HH-7 of this subpart,

$$MF = K \times \left(\frac{1}{CE} \sum_{n-1}^{N} \left[\frac{R_n}{f_{Rec,n}} \right] \right) \Big/ SArea$$

For Equation HH-8 of this subpart,

$$MF = K \times \left(\frac{1}{CE} \left\{ \sum_{n-1}^{N} \left[\frac{R_n}{f_{Rec,n}} \right] \right\} - \sum_{n-1}^{N} R_n \right) \Big/ SArea$$

Where:

MF = Methane flux rate from the landfill in the reporting year (grams per square meter per day, $g/m^2/d$).

K = unit conversion factor = $10^6/365$ (g/metric ton per days/year) or $10^6/366$ for a leap year.

SArea = The surface area of the landfill containing waste at the beginning of the reporting year (square meters, m^2).

G_{CH4} = Modeled methane generation rate in reporting year from Equation HH–1 of this subpart or Equation TT–1 of subpart TT of this part, as applicable, except for application with Equation HH–6 of this subpart (metric tons CH_4). For application with Equation HH–6 of this subpart, the greater of the modeled methane generation rate in reporting year from Equation HH–1 of this subpart or Equation TT–1 of this part, as applicable, and the quantity of recovered CH_4 from Equation HH–4 of this subpart (metric tons CH_4).

CE = Collection efficiency estimated at landfill, taking into account system coverage, operation, and cover system materials from Table HH–3 of this subpart. If area by soil cover type information is not available, use default value of 0.75 (CE4 in table HH–3 of this subpart) for all areas under active influence of the collection system.

N = Number of landfill gas measurement locations (associated with a destruction device or gas sent off-site). If a single monitoring location is used to monitor volumetric flow and CH_4 concentration of the recovered gas sent to one or multiple destruction devices, then N=1.

R_n = Quantity of recovered CH_4 from Equation HH–4 of this subpart for the nth measurement location (metric tons).

$f_{Rec,n}$ = Fraction of hours the recovery system associated with the nth measurement location was operating (annual operating hours/8760 hours per year or annual operating hours/8784 hours per year for a leap year).

[78 FR 71971, Nov. 29, 2013]

Subpart II—Industrial Wastewater Treatment

SOURCE: 75 FR 39767, July 12, 2010, unless otherwise noted.

§ 98.350 Definition of source category.

(a) This source category consists of anaerobic processes used to treat industrial wastewater and industrial wastewater treatment sludge at facilities that perform the operations listed in this paragraph.

(1) Pulp and paper manufacturing.

(2) Food processing.

(3) Ethanol production.

(4) Petroleum refining.

(b) An *anaerobic process* is a procedure in which organic matter in wastewater, wastewater treatment sludge, or other material is degraded by micro-organisms in the absence of oxygen, resulting in the generation of CO_2 and CH_4. This source category consists of the following: anaerobic reactors, anaerobic lagoons, anaerobic sludge digesters, and biogas destruction devices (for example, burners, boilers, turbines, flares, or other devices).

(1) An *anaerobic reactor* is an enclosed vessel used for anaerobic wastewater treatment (*e.g.*, upflow anaerobic sludge blanket, fixed film).

(2) An*anaerobic sludge digester* is an enclosed vessel in which wastewater treatment sludge is degraded anaerobically.

(3) An*anaerobic lagoon* is a lined or unlined earthen basin used for wastewater treatment, in which oxygen is absent throughout the depth of the basin, except for a shallow surface zone. Anaerobic lagoons are not equipped with surface aerators. Anaerobic lagoons are classified as deep (depth more than 2 meters) or shallow (depth less than 2 meters).

(c) This source category does not include municipal wastewater treatment plants or separate treatment of sanitary wastewater at industrial sites.

[75 FR 39767, July 12, 2010, as amended at 76 FR 73903, Nov. 29, 2011]

§ 98.351 Reporting threshold.

You must report GHG emissions under this subpart if your facility meets all of the conditions under paragraphs (a) or (b) of this section:

(a) *Petroleum refineries and pulp and paper manufacturing.*

(1) The facility is subject to reporting under subpart Y of this part (Petroleum Refineries) or subpart AA of this part (Pulp and Paper Manufacturing).

(2) The facility meets the requirements of either § 98.2(a)(1) or (2).

(3) The facility operates an anaerobic process to treat industrial wastewater and/or industrial wastewater treatment sludge.

(b) *Ethanol production and food processing facilities.*

(1) The facility performs an ethanol production or food processing operation, as defined in § 98.358 of this subpart.

(2) The facility meets the requirements of § 98.2(a)(2).

(3) The facility operates an anaerobic process to treat industrial wastewater

and/or industrial wastewater treatment sludge.

§ 98.352 GHGs to report.

(a) You must report CH_4 generation, CH_4 emissions, and CH_4 recovered from treatment of industrial wastewater at each anaerobic lagoon and anaerobic reactor.

(b) You must report CH_4 emissions and CH_4 recovered from each anaerobic sludge digester.

(c) You must report CH_4 emissions and CH_4 destruction resulting from each biogas collection and biogas destruction device.

(d) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit associated with the biogas destruction device, if present, by following the requirements of subpart C of this part.

[75 FR 39767, July 12, 2010, as amended at 76 FR 73903, Nov. 29, 2011]

§ 98.353 Calculating GHG emissions.

(a) For each anaerobic reactor and anaerobic lagoon, estimate the annual mass of CH_4 generated according to the applicable requirements in paragraphs (a)(1) through (a)(2) of this section.

(1) If you measure the concentration of organic material entering the anaerobic reactors or anaerobic lagoon using methods for the determination of chemical oxygen demand (COD), then estimate annual mass of CH_4 generated using Equation II–1 of this section.

$$CH_4G_n = \sum_{w=1}^{52}\left[Flow_w * COD_w * B_o * MCF * 0.001\right] \qquad \text{(Eq. II-1)}$$

Where:

CH_4G_n = Annual mass CH_4 generated from the nth anaerobic wastewater treatment process (metric tons).

n = Index for processes at the facility, used in Equation II–7.

w = Index for weekly measurement period.

$Flow_w$ = Volume of wastewater sent to an anaerobic wastewater treatment process in week w (m^3/week), measured as specified in § 98.354(d).

COD_w = Average weekly concentration of chemical oxygen demand of wastewater entering an anaerobic wastewater treatment process (for week w)(kg/m^3), measured as specified in § 98.354(b) and (c).

B_0 = Maximum CH_4 producing potential of wastewater (kg CH_4/kg COD), use the value 0.25.

MCF = CH_4 conversion factor, based on relevant values in Table II–1 of this subpart.

0.001 = Conversion factor from kg to metric tons.

(2) If you measure the concentration of organic material entering an anaerobic reactor or anaerobic lagoon using methods for the determination of 5-day biochemical oxygen demand (BOD_5), then estimate annual mass of CH_4 generated using Equation II–2 of this section.

$$CH_4G_n = \sum_{w=1}^{52}\left[Flow_w * BOD_{5,w} * B_o * MCF * 0.001\right] \qquad \text{(Eq. II-2)}$$

Where:

CH_4G_n = Annual mass of CH_4 generated from the anaerobic wastewater treatment process (metric tons).

n = Index for processes at the facility, used in Equation II–7.

w = Index for weekly measurement period.

$Flow_w$ = Volume of wastewater sent to an anaerobic wastewater treatment process in week w(m^3/week), measured as specified in § 98.354(d).

$BOD_{5,w}$ = Average weekly concentration of 5-day biochemical oxygen demand of wastewater entering an anaerobic wastewater treatment process for week w(kg/m^3), measured as specified in § 98.354(b) and (c).

B_0 = Maximum CH_4 producing potential of wastewater (kg CH_4/kg BOD_5), use the value 0.6.

MCF = CH_4 conversion factor, based on relevant values in Table II–1 to this subpart.

0.001 = Conversion factor from kg to metric tons.

(b) For each anaerobic reactor and anaerobic lagoon from which biogas is not recovered, estimate annual CH_4 emissions using Equation II–3 of this section.

$$CH_4E_n = CH_4G_n \qquad \text{(Eq. II-3)}$$

Where:

CH_4E_n = Annual mass of CH_4 emissions from the wastewater treatment process n from which biogas is not recovered (metric tons).

CH_4G_n = Annual mass of CH_4 generated from the wastewater treatment process n, as calculated in Equation II–1 or II–2 of this section (metric tons).

(c) For each anaerobic sludge digester, anaerobic reactor, or anaerobic lagoon from which some biogas is recovered, estimate the annual mass of CH_4 recovered according to the requirements in paragraphs (c)(1) and (c)(2) of this section. To estimate the annual mass of CH_4 recovered, you must continuously monitor biogas flow rate and determine the volume of biogas each week and the cumulative volume of biogas each year that is collected and routed to a destruction device as specified in § 98.354(h). If the gas flow meter is not equipped with automatic correction for temperature, pressure, or, if necessary, moisture content, you must determine these parameters as specified in paragraph (c)(2)(ii) of this section.

(1) If you continuously monitor CH_4 concentration (and if necessary, temperature, pressure, and moisture content required as specified in § 98.354(f)) of the biogas that is collected and routed to a destruction device using a monitoring meter specifically for CH_4 gas, as specified in § 98.354(g), you must use this monitoring system and calculate the quantity of CH_4 recovered for destruction using Equation II–4 of this section. A fully integrated system that directly reports CH_4 quantity requires only the summing of results of all monitoring periods for a given year.

$$R_n = \sum_{m=1}^{M}\left[(V)_m * (K_{MC})_m * \frac{(C_{CH4})_m}{100\%} * 0.0423 * \frac{520°R}{(T)_m} * \frac{(P)_m}{1\ atm} * \frac{0.454}{1{,}000}\right] \qquad \text{(Eq. II-4)}$$

Where:

R_n = Annual quantity of CH_4 recovered from the nth anaerobic reactor, sludge digester, or lagoon (metric tons CH_4/yr)

n = Index for processes at the facility, used in Equation II–7.

M = Total number of measurement periods in a year. Use M = 365 (M = 366 for leap years) for daily averaging of continuous monitoring, as provided in paragraph (c)(1)of this section. Use M = 52 for weekly sampling, as provided in paragraph (c)(2)of this section.

m = Index for measurement period.

V_m = Cumulative volumetric flow for the measurement period in actual cubic feet (acf). If no biogas was recovered during a monitoring period, use zero.

$(K_{MC})_m$ = Moisture correction term for the measurement period, volumetric basis.

= 1 when $(V)_m$ and $(C_{CH4})_m$ are measured on a dry basis or if both are measured on a wet basis.

= $1-(f_{H2O})_m$ when $(V)_m$ is measured on a wet basis and $(C_{CH4})_m$ is measured on a dry basis.

= $1/[1-(f_{H2O})_m]$ when $(V)_m$ is measured on a dry basis and $(C_{CH4})_m$ is measured on a wet basis.

$(f_{H2O})_m$ = Average moisture content of biogas during the measurment period, volumetric basis, (cubic feet water per cubic feet biogas).

$(C_{CH4})_m$ = Average CH_4 concentration of biogas during the measurement period, (volume %).

0.0423 = Density of CH_4 lb/cf at 520 °R or 60 °F and 1 atm.

520 °R = 520 degrees Rankine.

T_m = Average temperature at which flow is measured for the measurement period (°R). If the flow rate meter automatically corrects for temperature to 520° R, replace ''520° R/T_m'' with ''1''.

P_m = Average pressure at which flow is measured for the measurement period (atm).

If the flow rate meter automatically corrects for pressure to 1 atm, replace “P_m/1” with “1”.

0.454/1,000 = Conversion factor (metric ton/lb).

(2) If you do not continuously monitor CH_4 concentration according to paragraph (c)(1) of this section, you must determine the CH_4 concentration, temperature, pressure, and, if necessary, moisture content of the biogas that is collected and routed to a destruction device according to the requirements in paragraphs (c)(2)(i) through (c)(2)(ii) of this section and calculate the quantity of CH_4 recovered for destruction using Equation II–4 of this section.

(i) Determine the CH_4 concentration in the biogas that is collected and routed to a destruction device in a location near or representative of the location of the gas flow meter at least once each calendar week; if only one measurement is made each calendar week, there must be least three days between measurements. For a given calendar week, you are not required to determine CH_4 concentration if the cumulative volume of biogas for that calendar week, determined as specified in paragraph (c) of this section, is zero.

(ii) If the gas flow meter is not equipped with automatic correction for temperature, pressure, or, if necessary, moisture content:

(A) Determine the temperature and pressure in the biogas that is collected and routed to a destruction device in a location near or representative of the location of the gas flow meter at least once each calendar week; if only one measurement is made each calendar week, there must be at least three days between measurements.

(B) If the CH_4 concentration is determined on a dry basis and biogas flow is determined on a wet basis, or CH_4 concentration is determined on a wet basis and biogas flow is determined on a dry basis, and the flow meter does not automatically correct for moisture content, determine the moisture content in the biogas that is collected and routed to a destruction device in a location near or representative of the location of the gas flow meter at least once each calendar week that the cumulative biogas flow measured as specified in §98.354(h) is greater than zero; if only one measurement is made each calendar week, there must be at least three days between measurements.

(d) For each anaerobic sludge digester, anaerobic reactor, or anaerobic lagoon from which some quantity of biogas is recovered, you must estimate both the annual mass of CH_4 that is generated, but not recovered, according to paragraph (d)(1) of this section and the annual mass of CH_4 emitted according to paragraph (d)(2) of this section.

(1) Estimate the annual mass of CH_4 that is generated, but not recovered, using Equation II–5 of this section.

$$CH_4L_n = R_n * \left(\frac{1}{\text{CE}} - 1\right) \qquad \text{(Eq. II-5)}$$

Where:

CH_4L_n = Leakage at the anaerobic process n (metric tons CH_4).

n = Index for processes at the facility, used in Equation II–7.

R_n = Annual quantity of CH_4 recovered from the nth anaerobic reactor, anaerobic lagoon, or anaerobic sludge digester, as calculated in Equation II–4 of this section (metric tons CH_4).

CE = CH_4 collection efficiency of anaerobic process n, as specified in Table II–2 of this subpart (decimal).

(2) For each anaerobic sludge digester, anaerobic reactor, or anaerobic lagoon from which some quantity of biogas is recovered, estimate the annual mass of CH_4 emitted using Equation II–6 of this section.

$$CH_4E_n = CH_4L_n + R_n\ (1- [\ (D_{E1} * f_{Dest\_1}\ ) + (DE_2 * f_{Dest\_2})])\qquad \text{(Eq. II-6)}$$

Where:

CH_4E_n = Annual quantity of CH_4 emitted from the process n from which biogas is recovered (metric tons).

n = Index for processes at the facility, used in Equation II–7.

CH_4L_n = Leakage at the anaerobic process n, as calculated in Equation II–5 of this section (metric tons CH_4).

R_n = Annual quantity of CH_4 recovered from the nth anaerobic reactor or anaerobic sludge digester, as calculated in Equation II–4 of this section (metric tons CH_4).

DE_1 = Primary destruction device CH_4 destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99). If the biogas is transported off-site for destruction, use DE = 1.

$f_{Dest\text{—}1}$ = Fraction of hours the primary destruction device was operating calculated as the annual hours when the destruction device was operating divided by the annual operating hours of the biogas recovery system. If the biogas is transported off-site for destruction, use f_{Dest} = 1.

DE_2 = Back-up destruction device CH_4 destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99).

$f_{Dest\text{—}2}$ = Fraction of hours the back-up destruction device was operating calculated as the annual hours when the destruction device was operating divided by the annual operating hours of the biogas recovery system.

(e) Estimate the total mass of CH_4 emitted from all anaerobic processes from which biogas is not recovered (calculated in Eq. II–3) and all anaerobic processes from which some biogas is recovered (calculated in Equation II–6) using Equation II–7 of this section.

$$CH_4E_T = \sum_{n=1}^{j} CH_4E_n \qquad \text{(Eq. II-7)}$$

Where:

CH_4E_T = Annual mass CH_4 emitted from all anaerobic processes at the facility (metric tons).

n = Index for processes at the facility.

CH_4E_n = Annual mass of CH_4 emissions from process n (metric tons).

j = Total number of processes from which methane is emitted.

[75 FR 39767, July 12, 2010, as amended at 76 FR 73903, Nov. 29, 2011; 78 FR 71972, Nov. 29, 2013]

§ 98.354 Monitoring and QA/QC requirements.

(a) For calendar year 2011 monitoring, the facility may submit a request to the Administrator to use one or more best available monitoring methods as listed in § 98.3(d)(1)(i) through (iv). The request must be submitted no later than October 12, 2010 and must contain the information in § 98.3(d)(2)(ii). To obtain approval, the request must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2011. The use of best available monitoring methods will not be approved beyond December 31, 2011.

(b) You must determine the concentration of organic material in wastewater treated anaerobically using analytical methods for COD or BOD_5 specified in 40 CFR 136.3 Table 1B. For the purpose of determining concentrations of wastewater influent to the anaerobic wastewater treatment process, samples may be diluted to the concentration range of the approved method, but the calculated concentration of the undiluted wastewater must be used for calculations and reporting required by this subpart.

(c) You must collect samples representing wastewater influent to the anaerobic wastewater treatment process, following all preliminary and primary treatment steps (*e.g.*, after grit removal, primary clarification, oil-water separation, dissolved air flotation, or similar solids and oil separation processes). You must collect and analyze samples for COD or BOD_5 concentration at least once each calendar week that the anaerobic wastewater treatment process is operating; if only one measurement is made each calendar week, there must be at least three days between measurements. You must collect a sample that represents the average COD or BOD_5 concentration of the waste stream over a 24-hour sampling period. You must collect a minimum of four sample aliquots per 24-hour period and composite the aliquots for analysis. Collect a flow-proportional composite sample (either constant time interval between samples with sample volume proportional to stream flow, or constant sample volume with time interval between samples proportional to stream flow). Follow sampling procedures and techniques presented in Chapter 5, Sampling, of the ‘‘NPDES Compliance Inspection Manual,’’ (incorporated by reference, *see* § 98.7) or Section 7.1.3, Sample Collection Methods, of the ‘‘U.S.

EPA NPDES Permit Writers' Manual,'' (incorporated by reference, *see* § 98.7).

(d) You must measure the flowrate of wastewater entering anaerobic wastewater treatment process at least once each calendar week that the process is operating; if only one measurement is made each calendar week, there must be at least three days between measurements. You must measure the flowrate for the 24-hour period for which you collect samples analyzed for COD or BOD_5 concentration. The flow measurement location must correspond to the location used to collect samples analyzed for COD or BOD_5 concentration. You must measure the flowrate using one of the methods specified in paragraphs (d)(1) through (d)(5) of this section or as specified by the manufacturer.

(1) ASME MFC–3M–2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, *see* § 98.7).

(2) ASME MFC–5M–1985 (Reaffirmed 1994) Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters (incorporated by reference, *see* § 98.7).

(3) ASME MFC–16–2007 Measurement of Liquid Flow in Closed Conduits with Electromagnetic Flowmeters (incorporated by reference, *see* § 98.7).

(4) ASTM D1941–91 (Reapproved 2007) Standard Test Method for Open Channel Flow Measurement of Water with the Parshall Flume, approved June 15, 2007, (incorporated by reference, *see* § 98.7).

(5) ASTM D5614–94 (Reapproved 2008) Standard Test Method for Open Channel Flow Measurement of Water with Broad-Crested Weirs, approved October 1, 2008, (incorporated by reference, *see* § 98.7).

(e) All wastewater flow measurement devices must be calibrated prior to the first year of reporting and recalibrated either biennially (every 2 years) or at the minimum frequency specified by the manufacturer. Wastewater flow measurement devices must be calibrated using the procedures specified by the device manufacturer.

(f) For each anaerobic process (such as anaerobic reactor, sludge digester, or lagoon) from which biogas is recovered, you must make the measurements or determinations specified in paragraphs (f)(1) through (f)(3) of this section.

(1) You must continuously measure the biogas flow rate as specified in paragraph (h) of this section and determine the cumulative volume of biogas recovered.

(2) You must determine the CH_4 concentration of the recovered biogas as specified in paragraph (g) of this section at a location near or representative of the location of the gas flow meter. You must determine CH_4 concentration either continuously or intermittently. If you determine the concentration intermittently, you must determine the concentration at least once each calendar week that the cumulative biogas flow measured as specified in paragraph (h) of this section is greater than zero, with at least three days between measurements.

(3) As specified in § 98.353(c) and paragraph (h) of this section, you must determine temperature, pressure, and moisture content as necessary to accurately determine the biogas flow rate and CH_4 concentration. You must determine temperature and pressure if the gas flow meter or gas composition monitor do not automatically correct for temperature or pressure. You must measure moisture content of the recovered biogas if the biogas flow rate is measured on a wet basis and the CH_4 concentration is measured on a dry basis. You must also measure the moisture content of the recovered biogas if the biogas flow rate is measured on a dry basis and the CH_4 concentration is measured on a wet basis.

(g) For each anaerobic process (such as an anaerobic reactor, sludge digester, or lagoon) from which biogas is recovered, operate, maintain, and calibrate a gas composition monitor capable of measuring the concentration of CH_4 in the recovered biogas using one of the methods specified in paragraphs (g)(1) through (g)(6) of this section or as specified by the manufacturer.

(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 Standard 2261–00, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography (incorporated by reference, *see* § 98.7).

(5) ASTM UOP539–97 Refinery Gas Analysis by Gas Chromatography (incorporated by reference, *see* § 98.7).

(6) As an alternative to the gas chromatography methods provided in paragraphs (g)(1) through (g)(5) of this section, you may use total gaseous organic concentration analyzers and calculate the CH_4 concentration following the requirements in paragraphs (g)(6)(i) through (g)(6)(iii) of this section.

(i) Use Method 25A or 25B at 40 CFR part 60, appendix A–7 to determine total gaseous organic concentration. You must calibrate the instrument with CH_4 and determine the total gaseous organic concentration as carbon (or as CH_4; K=1 in Equation 25A–1 of Method 25A at 40 CFR part 60, appendix A–7).

(ii) Determine a non-methane organic carbon correction factor at the routine sampling location no less frequently than once a reporting year following the requirements in paragraphs (g)(6)(ii)(A) through (g)(6)(ii)(C) of this section.

(A) Take a minimum of three grab samples of the biogas with a minimum of 20 minutes between samples and determine the methane composition of the biogas using one of the methods specified in paragraphs (g)(1) through (g)(5) of this section.

(B) As soon as practical after each grab sample is collected and prior to the collection of a subsequent grab sample, determine the total gaseous organic concentration of the biogas using either Method 25A or 25B at 40 CFR part 60, appendix A–7 as specified in paragraph (g)(6)(i) of this section.

(C) Determine the arithmetic average methane concentration and the arithmetic average total gaseous organic concentration of the samples analyzed according to paragraphs (g)(6)(ii)(A) and (g)(6)(ii)(B) of this section, respectively, and calculate the non-methane organic carbon correction factor as the ratio of the average methane concentration to the average total gaseous organic concentration. If the ratio exceeds 1, use 1 for the non-methane organic carbon correction factor.

(iii) Calculate the CH_4 concentration as specified in Equation II–8 of this section.

$$C_{CH4} = f_{NMOC} \times C_{TGOC} \qquad \text{(Eq. II-8)}$$

Where:

C_{CH_4} = Methane (CH_4) concentration in the biogas (volume %) for use in Equation II–4 of this subpart.

f_{NMOC} = Non-methane organic carbon correction factor from the most recent determination of the non-methane organic carbon correction factor as specified in paragraph (g)(6)(ii) of this section (unitless).

C_{TGOC} = Total gaseous organic carbon concentration measured using Method 25A or 25B at 40 CFR part 60, appendix A–7 during routine monitoring of the biogas (volume %).

(h) For each anaerobic process (such as an anaerobic reactor, sludge digester, or lagoon) from which biogas is recovered, install, operate, maintain, and calibrate a gas flow meter capable of continuously measuring the volumetric flow rate of the recovered biogas using one of the methods specified in paragraphs (h)(1) through (h)(8) of this section or as specified by the manufacturer. Recalibrate each gas flow meter either biennially (every 2 years) or at the minimum frequency specified by the manufacturer. Except as provided in § 98.353(c)(2)(iii), each gas flow meter must be capable of correcting for the temperature and pressure and, if necessary, moisture content.

(1) ASME MFC–3M–2004, Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, *see* § 98.7).

(2) ASME MFC–4M–1986 (Reaffirmed 1997), Measurement of Gas Flow by Turbine Meters (incorporated by reference, *see* § 98.7).

(3) ASME MFC–6M–1998, Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, *see* § 98.7).

(4) ASME MFC–7M–1987 (Reaffirmed 1992), Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, *see* § 98.7).

(5) ASME MFC–11M–2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters (incorporated by reference, see § 98.7). The mass flow must be corrected to volumetric flow based on the measured temperature, pressure, and biogas composition.

(6) ASME MFC–14M–2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, *see* § 98.7).

(7) ASME MFC–18M–2001 Measurement of Fluid Flow using Variable Area Meters (incorporated by reference, *see* § 98.7).

(8) Method 2A or 2D at 40 CFR part 60, appendix A–1.

(i) All temperature, pressure, and, moisture content monitors required as specified in paragraph (f) of this section must be calibrated using the procedures and frequencies where specified by the device manufacturer, if not specified use an industry accepted or industry standard practice.

(j) All equipment (temperature, pressure, and moisture content monitors and gas flow meters and gas composition monitors) must be maintained as specified by the manufacturer.

(k) If applicable, the owner or operator must document the procedures used to ensure the accuracy of measurements of COD or BOD_5 concentration, wastewater flow rate, biogas flow rate, biogas composition, temperature, pressure, and moisture content. These procedures include, but are not limited to, calibration of gas flow meters, and other measurement devices. The estimated accuracy of measurements made with these devices must also be recorded, and the technical basis for these estimates must be documented.

[75 FR 39767, July 12, 2010, as amended at 76 FR 73904, Nov. 29, 2011]

§ 98.355 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (*e.g.*, if a meter malfunctions during unit operation or if a required sample is not taken), a substitute data value for the missing parameter must be used in the calculations, according to the following requirements in paragraphs (a) through (c) of this section:

(a) For each missing weekly value of COD or BOD_5 or wastewater flow entering an anaerobic wastewater treatment process, the substitute data value must be the arithmetic average of the quality-assured values of those parameters for the week immediately preceding and the week immediately following the missing data incident.

(b) For each missing value of the CH_4 content or biogas flow rates, the substitute data value must be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident.

(c) If, for a particular parameter, no quality-assured data are available prior to the missing data incident, the substitute data value must be the first quality-assured value obtained after the missing data period. If, for a particular parameter, the ‘‘after’’ value is not obtained by the end of the reporting year, you may use the last quality-assured value obtained ‘‘before’’ the missing data period for the missing data substitution. You must document and keep records of the procedures you use for all such estimates.

[75 FR 39767, July 12, 2010, as amended at 76 FR 73905, Nov. 29, 2011]

§ 98.356 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each wastewater treatment system.

(a) A description or diagram of the industrial wastewater treatment system, identifying the processes used to treat industrial wastewater and industrial wastewater treatment sludge. Indicate how the processes are related to each other and identify the anaerobic processes. Provide a unique identifier for each anaerobic process, indicate the average depth in meters of each anaerobic lagoon, and indicate whether biogas generated by each anaerobic process is recovered. The anaerobic processes must be identified as:

(1) Anaerobic reactor.

(2) Anaerobic deep lagoon (depth more than 2 meters).

(3) Anaerobic shallow lagoon (depth less than 2 meters).

(4) Anaerobic sludge digester.

(b) For each anaerobic wastewater treatment process (reactor, deep lagoon, or shallow lagoon) you must report:

(1) Weekly average COD or BOD_5 concentration of wastewater entering each anaerobic wastewater treatment process, for each week the anaerobic process was operated.

(2) Volume of wastewater entering each anaerobic wastewater treatment process for each week the anaerobic process was operated.

(3) Maximum CH_4 production potential (B_0) used as an input to Equation II–1 or II–2 of this subpart, from Table II–1 to this subpart.

(4) Methane conversion factor (MCF) used as an input to Equation II–1 or II–2 of this subpart, from Table II–1 to this subpart.

(5) Annual mass of CH_4 generated by each anaerobic wastewater treatment process, calculated using Equation II–1 or II–2 of this subpart.

(c) For each anaerobic wastewater treatment process from which biogas is not recovered, you must report the annual CH_4 emissions, calculated using Equation II–3 of this subpart.

(d) For each anaerobic wastewater treatment process and anaerobic sludge digester from which some biogas is recovered, you must report:

(1) Annual quantity of CH_4 recovered from the anaerobic process calculated using Equation II–4 of this subpart.

(2) Total weekly volumetric biogas flow for each week (up to 52 weeks/year) that biogas is collected for destruction.

(3) Weekly average CH_4 concentration for each week that biogas is collected for destruction.

(4) Weekly average biogas temperature for each week at which flow is measured for biogas collected for destruction, or statement that temperature is incorporated into monitoring equipment internal calculations.

(5) Whether flow was measured on a wet or dry basis, whether CH_4 concentration was measured on a wet or dry basis, and if required for Equation II–4 of this subpart, weekly average moisture content for each week at which flow is measured for biogas collected for destruction, or statement that moisture content is incorporated into monitoring equipment internal calculations.

(6) Weekly average biogas pressure for each week at which flow is measured for biogas collected for destruction, or statement that pressure is incorporated into monitoring equipment internal calculations.

(7) CH_4 collection efficiency (CE) used in Equation II–5 of this subpart.

(8) Whether destruction occurs at the facility or off-site. If destruction occurs at the facility, also report whether a back-up destruction device is present at the facility, the annual operating hours for the primary destruction device, the annual operating hours for the back-up destruction device (if present), the destruction efficiency for the primary destruction device, and the destruction efficiency for the back-up destruction device (if present).

(9) For each anaerobic process from which some biogas is recovered, you must report the annual CH_4 emissions, as calculated by Equation II–6 of this subpart.

(e) The total mass of CH_4 emitted from all anaerobic processes from which biogas is not recovered (calculated in Equation II–3 of this subpart) and from all anaerobic processes from which some biogas is recovered (calculated in Equation II–6 of this subpart) using Equation II–7 of this subpart.

[75 FR 39767, July 12, 2010, as amended at 76 FR 73905, Nov. 29, 2011]

§ 98.357 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the calibration records for all monitoring equipment, including the method or manufacturer's specification used for calibration.

§ 98.358 Definitions.

Except as provided below, all terms used in this subpart have the same meaning given in the CAA and subpart A of this part.

Biogas means the combination of CO_2, CH_4, and other gases produced by the biological breakdown of organic matter in the absence of oxygen.

Ethanol production means an operation that produces ethanol from the fermentation of sugar, starch, grain, or cellulosic biomass feedstocks, or the production of ethanol synthetically from petrochemical feedstocks, such as ethylene or other chemicals.

Food processing means an operation used to manufacture or process meat, poultry, fruits, and/or vegetables as defined under NAICS 3116 (Meat Product Manufacturing) or NAICS 3114 (Fruit and Vegetable Preserving and Specialty Food Manufacturing). For information on NAICS codes, *see http://www.census.gov/eos/www/naics/.*

Industrial wastewater means water containing wastes from an industrial process. Industrial wastewater includes water which comes into direct contact with or results from the storage, production, or use of any raw material, intermediate product, finished product, by-product, or waste product. Examples of industrial wastewater include, but are not limited to, paper mill white water, wastewater from equipment cleaning, wastewater from air pollution control devices, rinse water, contaminated stormwater, and contaminated cooling water.

Industrial wastewater treatment sludge means solid or semi-solid material resulting from the treatment of industrial wastewater, including but not limited to biosolids, screenings, grit, scum, and settled solids.

Wastewater treatment system means the collection of all processes that treat or remove pollutants and contaminants, such as soluble organic matter, suspended solids, pathogenic organisms, and chemicals from wastewater prior to its reuse or discharge from the facility.

TABLE II–1 TO SUBPART II OF PART 98—EMISSION FACTORS

Factors	Default value	Units
B_0—for facilities monitoring COD	0.25	Kg CH_4/kg COD
B_0—for facilities monitoring BOD_5	0.60	Kg CH_4/kg BOD_5
MCF—anaerobic reactor	0.8	Fraction.
MCF—anaerobic deep lagoon (depth more than 2 m)	0.8	Fraction.
MCF—anaerobic shallow lagoon (depth less than 2 m)	0.2	Fraction.

TABLE II–2 TO SUBPART II—COLLECTION EFFICIENCIES OF ANAEROBIC PROCESSES

Anaerobic process type	Cover type	Methane collection efficiency
Covered anaerobic lagoon (biogas capture)	Bank to bank, impermeable	0.975
	Modular, impermeable	0.70
Anaerobic sludge digester; anaerobic reactor	Enclosed Vessel	0.99

Subpart JJ—Manure Management

§ 98.360 Definition of the source category.

(a) This source category consists of livestock facilities with manure management systems that emit 25,000 metric tons CO_2e or more per year.

(1) Table JJ–1 presents the minimum average annual animal population by animal group that is estimated to emit 25,000 metric tons CO_2e or more per year. Facilities with an average annual animal population, as described in § 98.363(a)(1) and (2), below those listed in Table JJ–1 do not need to report under this rule. A facility with an annual animal population that exceeds those listed in Table JJ–1 should conduct a more thorough analysis to determine applicability.

(2) (i) If a facility has more than one animal group present (e.g., swine and poultry), the facility must determine if they are required to report by calculating the combined animal group factor (CAGF) using equation JJ–1:

$$CAGF = \sum_{\text{Animal Groups}} \left(\frac{AAAP_{AG,\ Facility}}{APTL_{AG}} \right) \quad \text{(Eq. JJ-1)}$$

Where:

CAGF = Combined Animal Group Factor

$AAAP_{AG,Facility}$ = Average annual animal population at the facility, by animal group

$APTL_{AG}$ = Animal population threshold level, as specified in Table JJ–1 of this section

(ii) If the calculated CAGF for a facility is less than 1, the facility is not required to report under this rule. If the CAGF is equal to or greater than 1, the facility must use more detailed applicability tables and tools to determine if they are required to report under this rule.

(b) A manure management system (MMS) is a system that stabilizes and/or stores livestock manure, litter, or manure wastewater in one or more of the following system components: Uncovered anaerobic lagoons, liquid/slurry systems with and without crust covers (including but not limited to ponds and tanks), storage pits, digesters, solid manure storage, dry lots (including feedlots), high-rise houses for poultry production (poultry without litter), poultry production with litter, deep bedding systems for cattle and swine, manure composting, and aerobic treatment.

(c) This source category does not include system components at a livestock facility that are unrelated to the stabilization and/or storage of manure such as daily spread or pasture/range/paddock systems or land application activities or any method of manure utilization that is not listed in § 98.360(b).

(d) This source category does not include manure management activities located off site from a livestock facility or off-site manure composting operations.

§ 98.361 Reporting threshold.

Livestock facilities must report GHG emissions under this subpart if the facility meets the reporting threshold as defined in 98.360(a) above, contains a manure management system as defined in 98.360(b) above, and meets the requirements of § 98.2(a)(1).

§ 98.362 GHGs to report.

(a) Livestock facilities must report annual aggregate CH_4 and N_2O emissions for the following MMS components at the facility:

(1) Uncovered anaerobic lagoons.

(2) Liquid/slurry systems (with and without crust covers, and including but not limited to ponds and tanks).

(3) Storage pits.

(4) Digesters, including covered anaerobic lagoons.

(5) Solid manure storage.

(6) Dry lots, including feedlots.

(7) High-rise houses for poultry production (poultry without litter)

(8) Poultry production with litter.

(9) Deep bedding systems for cattle and swine.

(10) Manure composting.

(11) Aerobic treatment.

(b) A livestock facility that is subject to this rule only because of emissions from manure management system components is not required to report emissions from subparts C through PP (other than subpart JJ) of this part.

(c) A livestock facility that is subject to this part because of emissions from source categories described in subparts C through PP of this part is not required to report emissions under subpart JJ of this part unless emissions from manure management systems are 25,000 metric tons CO_2e per year or more.

§ 98.363 Calculating GHG emissions.

(a) For all manure management system components listed in 98.360(b) except digesters, estimate the annual CH_4 emissions and sum for all the components to obtain total emissions from the manure management system for all animal types using Equation JJ–1.

$$\text{CH}_4\ \text{Emissions}_{\text{MMS}}\ (\text{metric tons/yr}) = \sum_{\text{animal types}}\left[\sum_{\text{MMSC}}\left[\left(\text{TVS}_{\text{AT}}\ \text{x}\ \text{VS}_{\text{MMSC}}\ \text{x}\ \left(1-\text{VS}_{\text{ss}}\right)\ \text{x}\ 365\ \text{days/yr}\ \text{x}\ \left(\text{B}_0\right)_{\text{AT}}\ \text{x}\ \text{MCF}_{\text{MMSC}}\right)\text{x}\ 0.662\ \text{kg}\ \text{CH}_4/\text{m}^3\ \text{x}\ 1\ \text{metric ton}/1000\ \text{kg}\right]\right] \quad (\text{Eq. JJ-2})$$

Where:

MMSC = Manure management systems component.

TVS_{AT} = Total volatile solids excreted by animal type, calculated using Equation JJ–3 of this section (kg/day).

VS_{MMSC} = Fraction of the total manure for each animal type that is managed in MMS component MMSC, assumed to be equivalent to the fraction of VS in each MMS component.

VS_{ss} = Volatile solids removal through solid separation; if solid separation occurs prior to the MMS component, use a default value from Table JJ–4 of this section; if no solid separation occurs, this value is set to 0.

$(B_0)_{AT}$ = Maximum CH_4-producing capacity for each animal type, as specified in Table JJ–2 of this section (m^3 CH_4/kg VS).

MCF_{MMSC} = CH_4 conversion factor for the MMS component, as specified in Table JJ–5 of this section (decimal).

$$\mathbf{TVS_{AT} = Population_{AT} \times TAM_{AT} \times VS_{AT}/1000 \qquad (Eq.\ JJ\text{-}3)}$$

Where:

TVS_{AT} = Daily total volatile solids excreted per animal type (kg/day).

$Population_{AT}$ = Average annual animal population contributing manure to the manure management system by animal type (head) (see description in §98.363(a)(i) and (ii) below).

TAM_{AT} = Typical animal mass for each animal type, using either default values in Table JJ–2 of this section or farm-specific data (kg/head).

VS_{AT} = Volatile solids excretion rate for each animal type, using default values in Table JJ–2 or JJ–3 of this section (kg VS/day/1000 kg animal mass).

(1) Average annual animal populations for static populations (e.g., dairy cows, breeding swine, layers) must be estimated by performing an animal inventory or review of facility records once each reporting year.

(2) Average annual animal populations for growing populations (meat animals such as beef and veal cattle, market swine, broilers, and turkeys) must be estimated each year using the average number of days each animal is kept at the facility and the number of animals produced annually, and an equation similar or equal to Equation JJ–4 below, adapted from Equation 10.1 in *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, Volume 4, Chapter 10.

$$\text{Population}_{\text{AT}} = \text{Days onsite}_{\text{AT}} \times \left(\frac{\text{NAPA}_{\text{AT}}}{365}\right) \qquad (\text{Eq. JJ-4})$$

Where:

$Population_{AT}$ = Average annual animal population (by animal type).

Days $onsite_{AT}$ = Average number of days the animal is kept at the facility, by animal type.

$NAPA_{AT}$ = Number of animals produced annually, by animal type.

(b) For each digester, calculate the total amount of CH_4 emissions, and then sum the emissions from all digesters, as shown in Equation JJ–5 of this section.

$$\text{H}_4\ \text{Emissions}_{\text{AD}} = \sum_{1}^{\text{AD}} \left(\text{CH}_4\text{C} - \text{CH}_4\text{D} + \text{CH}_4\text{L}\right) \qquad \text{(Eq. JJ-5)}$$

Where:

CH_4 Emissions$_{AD}$ = CH_4 emissions from anaerobic digestion (metric tons/yr).

AD = Number of anaerobic digesters at the manure management facility.

CH_4C = CH_4 flow to digester combustion device, calculated using Equation JJ–6 of this section (metric tons CH_4/yr).

CH_4D = CH_4 destruction at digesters, calculated using Equation JJ–11 of this section (metric tons CH_4/yr)

CH_4L = Leakage at digesters calculated using Equation JJ–12 of this section (metric tons CH_4/yr).

(1) For each digester, calculate the annual CH_4 flow to the combustion device (CH_4C) using Equation JJ–6 of this section. A fully integrated system that directly reports the quantity of CH_4 flow to the digester combustion device requires only summing the results of all monitoring periods for a given year to obtain CH_4C.

$$\text{CH}_4\text{C} = \left(\text{V} \times \frac{\text{C}}{100\%} \times 0.0423 \times \frac{520^{\text{o}}\text{R}}{\text{T}} \times \frac{\text{P}}{1\ \text{atm}} \times \frac{0.454\ \text{metric ton}}{1{,}000\ \text{pounds}}\right) \qquad \text{(Eq. JJ-6)}$$

Where:

CH_4C = CH_4 flow to digester combustion device (metric tons CH_4/yr).

V = Average annual volumetric flow rate, calculated in Equation JJ–7 of this subsection (cubic feet CH_4/yr).

C = Average annual CH_4 concentration of digester gas, calculated in Equation JJ–8 of this section (%, wet basis).

0.0423 = Density of CH_4 lb/scf (at 520 °R or 60 °F and 1 atm).

T = Average annual temperature at which flow is measured, calculated in Equation JJ–9 of this section (°R).

P = Average annual pressure at which flow is measured, calculated in Equation JJ–10 of this section (atm).

(2) For each digester, calculate the average annual volumetric flow rate, CH_4 concentration of digester gas, temperature, and pressure at which flow are measured using Equations JJ–7 through JJ–10 of this section.

$$\text{V} = \frac{\sum_{n=1}^{\text{OD}} \left(\text{V}_n \times \frac{1{,}440\ \text{minutes}}{\text{day}}\right)}{\text{OD}} \qquad \text{(Eq. JJ-7)}$$

Where:

V = Average annual volumetric flow rate (cubic feet CH_4/yr).

OD = Operating days, number of days per year that that the digester was operating (days/yr).

V_n = Daily average volumetric flow rate for day n, as determined from daily monitoring as specified in § 98.364 (acfm).

$$\text{C} = \frac{\sum_{n=1}^{\text{OD}} \text{C}_n}{\text{OD}} \qquad \text{(Eq. JJ-8)}$$

Where:

C = Average annual CH_4 concentration of digester gas (%, wet basis).

OD = Operating days, number of days per year that the digester was operating (days/yr).

C_n = Average daily CH_4 concentration of digester gas for day n, as determined from daily monitoring as specified in § 98.364 (%, wet basis).

$$T = \frac{\sum_{n=1}^{OD} T_n}{OD} \qquad \text{(Eq. JJ-9)}$$

Where:

T = Average annual temperature at which flow is measured (°R).

OD = Operating days, number of days per year that the digester was operating (days/yr).

T_n = Temperature at which flow is measured for day n(°R).

$$P = \frac{\sum_{n=1}^{OD} P_n}{OD} \qquad \text{(Eq. JJ-10)}$$

Where:

P = Average annual pressure at which flow is measured (atm).

OD = Operating days, number of days per year that the digester was operating (days/yr).

P_n = Pressure at which flow is measured for day n (atm).

(3) For each digester, calculate the CH_4 destruction at the digester combustion device using Equation JJ–11 of this section.

$$CH_4D = CH_4C \times DE \times OH/Hours \qquad \text{(Eq. JJ-11)}$$

Where:

CH_4D = CH_4 destruction at digester combustion device (metric tons/yr).

CH_4C = Annual quantity of CH_4 flow to digester combustion device, as calculated in Equation JJ–6 of this section (metric tons CH_4).

DE = CH_4 destruction efficiency from flaring or burning in engine (lesser of manufacturer's specified destruction efficiency and 0.99). If the gas is transported off-site for destruction, use DE = 1.

OH = Number of hours combustion device is functioning in reporting year.

Hours = Hours in reporting year.

(4) For each digester, calculate the CH_4 leakage using Equation JJ–12 of this section.

$$CH_4L = CH_4C \times \left(\frac{1}{CE} - 1\right) \qquad \text{(Eq. JJ-12)}$$

Where:

CH_4L = Leakage at digesters (metric tons/yr).

CH_4C = Annual quantity of CH_4 flow to digester combustion device, as calculated in Equation JJ–6 of this section (metric tons CH_4).

CE = CH_4 collection efficiency of anaerobic digester, as specified in Table JJ–6 of this section (decimal).

(c) For each MMS component, estimate the annual N_2O emissions and sum for all MMS components to obtain total emissions from the manure management system for all animal types using Equation JJ–13 of this section.

$$\text{Direct } N_2O \text{ Emissions (metric tons/year)} = \sum\nolimits_{\text{animal types}} \left[\sum\nolimits_{MMSC} N_{ex\ AT} \times N_{ex,MMSC} \times \left(1 - N_{ss}\right) \times EF_{MMSC} \times 365 \text{ days/yr}\right] \times 44\ N_2O/28\ N_2O - N \times 1 \text{ metric ton}/1000 \text{ kg}\Big] \qquad \text{(Eq. JJ-13)}$$

Where:

$N_{ex\ AT}$ = Daily total nitrogen excreted per animal type, calculated using Equation JJ–14 of this section (kg N/day).

$N_{ex,MMSC}$ = Fraction of the total manure for each animal type that is managed in MMS component MMSC, assumed to be equivalent to the fraction of N_{ex} in each MMS component.

N_{ss} = Nitrogen removal through solid separation; if solid separation occurs prior to the MMS component, use a default value from Table JJ–4 of this section; if no solid separation occurs, this value is set to 0.

EF_{MMSC} = Emission factor for MMS component, as specified in Table JJ–7 of this section (kg N_2O-N/kg N).

$$N_{ex\ AT} = Population_{AT} \times TAM_{AT} \times N_{AT}/1000 \qquad \text{(Eq. JJ-14)}$$

Where:

$N_{ex\ AT}$ = Total nitrogen excreted per animal type (kg/day).

$Population_{AT}$ = Average annual animal population contributing manure to the manure management system by animal type (head) (see description in § 98.363(a)(i) and (ii)).

TAM_{AT} = Typical animal mass by animal type, using either default values in Table JJ–2 of this section or farm-specific data (kg/head).

N_{AT} = Nitrogen excretion rate by animal type, using default values in Tables JJ–2 or JJ–3 of this section (kg N/day/1000 kg animal mass).

(d) Estimate the annual total facility emissions using Equation JJ–15 of this section.

$$\text{Total Emissions (metric tons } CO_2e/yr) = \left[(CH_4\ emissions_{MMS} + CH_4\ emissions_{AD}) \times 21\right] + [\text{Direct } N_2O \text{ emissions} \times 310] \qquad \text{(Eq. JJ-15)}$$

Where:

$CH_4\ emissions_{MMS}$ = From Equation JJ–2 of this section.

$CH_4\ emissions_{AD}$ = From Equation JJ–5 of this section.

21 = Global Warming Potential of CH_4.

Direct N_2O emissions = From Equation JJ–13 of this section.

310 = Global Warming Potential of N_2O.

§ 98.364 Monitoring and QA/QC requirements.

(a) Perform an annual animal inventory or review of facility records (for static populations) or population calculation (for growing populations) to determine the average annual animal population for each animal type (see description in § 98.363(a)(1) and (2)).

(b) Perform an analysis on your operation to determine the fraction of total manure by weight for each animal type that is managed in each on-site manure management system component. If your system changes from previous reporting periods, you must reevaluate the fraction of total manure managed in each system component.

(c) The CH_4 concentration of gas from digesters must be determined using ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference *see* § 98.7). All gas composition monitors shall be calibrated prior to the first reporting year for biogas methane and carbon dioxide content using ASTM D1946–90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography (incorporated by reference *see* § 98.7)and recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent, or whenever the error in the midrange calibration check exceeds ±10 percent. All monitors shall be maintained as specified by the manufacturer.

(d) All temperature and pressure monitors must be calibrated using the procedures and frequencies specified by the manufacturer. All equipment (temperature and pressure monitors) shall be maintained as specified by the manufacturer.

(e) For digesters with gas collection systems, install, operate, maintain, and calibrate a gas flow meter capable of measuring the volumetric flow rate to provide data for the GHG emissions calculations, using the applicable methods specified in paragraphs (e)(1) through (e)(6) of this section or as specified by the manufacturer.

(1) ASME MFC–3M–2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi (incorporated by reference, *see* §98.7).

(2) ASME MFC–4M–1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters (incorporated by reference, *see* §98.7).

(3) ASME MFC–6M–1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters (incorporated by reference, *see* §98.7).

(4) ASME MFC–7M–1987 (Reaffirmed 1992) Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles (incorporated by reference, *see* §98.7).

(5) ASME MFC–14M–2003 Measurement of Fluid Flow Using Small Bore Precision Orifice Meters (incorporated by reference, *see* §98.7).

(6) ASME MFC–18M–2001 Measurement of Fluid Flow using Variable Area Meters (incorporated by reference, *see* §98.7).

(f) If applicable, the owner or operator shall document the procedures used to ensure the accuracy of gas flow rate, gas composition, temperature, and pressure measurements. These procedures include, but are not limited to, calibration of 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.

(g) Each gas flow meter shall be calibrated prior to the first reporting year and recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent. Each gas flow meter must have a rated accuracy of ±5 percent or lower and be capable of correcting for the temperature and pressure and, if the gas composition monitor determines CH_4 concentration on a dry basis, moisture content.

§98.365 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter 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, according to the requirements in paragraph (b) of this section.

(b) For missing gas flow rates or CH_4 content data, the substitute data value shall be the arithmetic average of the quality-assured values of that parameter immediately preceding and immediately following the missing data incident. 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.

§98.366 Data reporting requirements.

(a) In addition to the information required by §98.3(c), each annual report must contain the following information:

(1) List of manure management system components at the facility.

(2) Fraction of manure from each animal type that is handled in each manure management system component.

(3) Average annual animal population (for each animal type) for static populations or the results of Equation JJ–4 for growing populations.

(4) Average number of days that growing animals are kept at the facility (for each animal type).

(5) The number of animals produced annually for growing populations (for each animal type).

(6) Typical animal mass (for each animal type).

(7) Total facility emissions (results of Equation JJ–15).

(8) CH_4 emissions from manure management system components listed in §98.360(b), except digesters (results of Equation JJ–2).

(9) VS value used (for each animal type).

(10) B_0 value used (for each animal type).

(11) Methane conversion factor used for each MMS component.

(12) Average ambient temperature used to select each methane conversion factor.

(13) N_2O emissions (results of Equation JJ–13).

(14) N value used for each animal type.

(15) N_2O emission factor selected for each MMS component.

(b) Facilities with anaerobic digesters must also report:

(1) CH_4 emissions from anaerobic digesters (results of Equation JJ–5).

(2) CH_4 flow to the digester combustion device for each digester (results of Equation JJ–6, or value from fully integrated monitoring system as described in 98.363(b)).

(3) CH_4 destruction for each digester (results of Equation JJ–11).

(4) CH_4 leakage for each digester (results of Equation JJ–12).

(5) Total annual volumetric biogas flow for each digester (results of Equation JJ–7).

(6) Average annual CH_4 concentration for each digester (results of Equation JJ–8).

(7) Average annual temperature at which gas flow is measured for each digester (results of Equation JJ–9).

(8) Average annual gas flow pressure at which gas flow is measured for each digester (results of Equation JJ–10).

(9) Destruction efficiency used for each digester.

(10) Number of days per year that each digester was operating.

(11) Collection efficiency used for each digester.

§ 98.367 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the calibration records for all monitoring equipment, including the method or manufacturer's specification used for calibration.

§ 98.368 Definitions.

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

TABLE JJ–1 TO SUBPART JJ OF PART 98—ANIMAL POPULATION THRESHOLD LEVEL BELOW WHICH FACILITIES ARE NOT REQUIRED TO REPORT EMISSIONS UNDER SUBPART JJ [1] [2]

Animal group	Average annual animal population (Head) [3]
Beef	29,300
Dairy	3,200
Swine	34,100
Poultry:	
Layers	723,600
Broilers	38,160,000
Turkeys	7,710,000

[1] The threshold head populations in this table were calculated using the most conservative assumptions (high VS and N values, maximum ambient temperatures, and the application of an uncertainty factor) to ensure that facilities at or near the 25,000 metric ton CO_2e threshold level were not excluded from reporting.

[2] For facilities with more than one animal group present refer to § 98.360 (2) to estimate the combined animal group factor (CAGF), which is used to determine if a facility may be required to report.

[3] For all animal groups except dairy, the average annual animal population represents the total number of animals present at the facility. For dairy facilities, the average annual animal population represents the number of mature dairy cows present at the facility (note that heifers and calves were included in the emission estimates for dairy facilities using the assumption that the average annual animal population of heifers and calves at dairy facilities are equal to 30 percent of the mature dairy cow average annual animal population, therefore the average annual population for dairy facilities should not include heifers and calves, only dairy cows).

TABLE JJ–2 TO SUBPART JJ OF PART 98—WASTE CHARACTERISTICS DATA

Animal type	Typical animal mass (kg)	Volatile solids excretion rate (kg VS/day/1000 kg animal mass)	Nitrogen excretion rate (kg N/day/1000 kg animal mass)	Maximum methane generation potential, B_o (m^3 CH_4/kg VS added)
Dairy Cows	604	See Table JJ–3	See Table JJ–3	0.24
Dairy Heifers	476	See Table JJ–3	See Table JJ–3	0.17
Dairy Calves	118	6.41	0.30	0.17
Feedlot Steers	420	See Table JJ–3	See Table JJ–3	0.33

Animal type	Typical animal mass (kg)	Volatile solids excretion rate (kg VS/day/1000 kg animal mass)	Nitrogen excretion rate (kg N/day/1000 kg animal mass)	Maximum methane generation potential, B_o (m^3 CH_4/kg VS added)
Feedlot heifers	420	See Table JJ–3	See Table JJ–3	0.33
Market Swine <60 lbs	16	8.80	0.60	0.48
Market Swine 60–119 lbs	41	5.40	0.42	0.48
Market Swine 120–179 lbs	68	5.40	0.42	0.48
Market Swine >180 lbs	91	5.40	0.42	0.48
Breeding Swine	198	2.60	0.24	0.48
Feedlot Sheep	25	9.20	0.42	0.36
Goats	64	9.50	0.45	0.17
Horses	450	10.00	0.30	0.33
Hens >/= 1 yr	1.8	10.09	0.83	0.39
Pullets	1.8	10.09	0.62	0.39
Other Chickens	1.8	10.80	0.83	0.39
Broilers	0.9	15.00	1.10	0.36
Turkeys	6.8	9.70	0.74	0.36

TABLE JJ–3 TO SUBPART JJ OF PART 98—STATE-SPECIFIC VOLATILE SOLIDS (VS) AND NITROGEN (N) EXCRETION RATES FOR CATTLE

State	Volatile solids excretion rate (kg VS/day/1000 kg animal mass)				Nitrogen excretion rate (kg VS/day/1000 kg animal mass)			
	Dairy cows	Dairy heifers	Feedlot steer	Feedlot heifers	Dairy cows	Dairy heifers	Feedlot steer	Feedlot heifers
Alabama	8.40	8.35	4.27	4.74	0.50	0.46	0.36	0.38
Alaska	7.30	8.35	4.15	4.58	0.45	0.46	0.35	0.37
Arizona	10.37	8.35	3.91	4.27	0.58	0.46	0.33	0.34
Arkansas	7.59	8.35	3.98	4.35	0.46	0.46	0.33	0.35
California	10.02	8.35	3.96	4.33	0.56	0.46	0.33	0.34
Colorado	10.25	8.35	3.97	4.34	0.58	0.46	0.33	0.35
Connecticut	9.22	8.35	4.41	4.93	0.53	0.46	0.37	0.40
Delaware	8.63	8.35	4.19	4.64	0.51	0.46	0.35	0.37
Florida	8.90	8.35	4.15	4.58	0.52	0.46	0.35	0.37
Georgia	9.07	8.35	4.18	4.63	0.53	0.46	0.35	0.37
Hawaii	7.00	8.35	4.15	4.58	0.44	0.46	0.35	0.37
Idaho	10.11	8.35	4.03	4.42	0.57	0.46	0.34	0.35
Illinois	9.07	8.35	4.15	4.59	0.52	0.46	0.35	0.37
Indiana	9.38	8.35	3.98	4.35	0.54	0.46	0.33	0.35
Iowa	9.46	8.35	3.93	4.28	0.54	0.46	0.33	0.34
Kansas	9.63	8.35	3.97	4.35	0.55	0.46	0.33	0.35
Kentucky	7.89	8.35	4.20	4.65	0.48	0.46	0.35	0.37
Louisiana	7.39	8.35	4.07	4.48	0.45	0.46	0.34	0.36
Maine	8.99	8.35	4.07	4.47	0.52	0.46	0.34	0.36
Maryland	9.02	8.35	4.05	4.45	0.52	0.46	0.34	0.35
Massachusetts	8.63	8.35	4.15	4.58	0.51	0.46	0.35	0.37
Michigan	10.05	8.35	4.00	4.38	0.57	0.46	0.34	0.35
Minnesota	9.17	8.35	3.89	4.24	0.53	0.46	0.33	0.34
Mississippi	8.19	8.35	4.14	4.57	0.49	0.46	0.35	0.37
Missouri	8.02	8.35	4.08	4.49	0.48	0.46	0.34	0.36
Montana	9.03	8.35	4.23	4.69	0.52	0.46	0.36	0.38
Nebraska	9.09	8.35	3.98	4.35	0.53	0.46	0.33	0.35
Nevada	9.65	8.35	4.07	4.48	0.55	0.46	0.34	0.36
New Hampshire	9.44	8.35	3.94	4.30	0.54	0.46	0.33	0.34
New Jersey	8.51	8.35	3.98	4.36	0.50	0.46	0.33	0.35
New Mexico	10.34	8.35	3.88	4.22	0.58	0.46	0.32	0.33
New York	9.42	8.35	3.75	4.05	0.54	0.46	0.31	0.32
North Carolina	9.38	8.35	4.20	4.65	0.55	0.46	0.35	0.37
North Dakota	8.40	8.35	3.88	4.22	0.50	0.46	0.32	0.34
Ohio	9.01	8.35	3.96	4.33	0.52	0.46	0.33	0.34
Oklahoma	8.58	8.35	3.98	4.35	0.50	0.46	0.33	0.35
Oregon	9.40	8.35	4.06	4.46	0.54	0.46	0.34	0.36
Pennsylvania	9.26	8.35	3.98	4.35	0.53	0.46	0.33	0.35
Rhode Island	8.94	8.35	4.36	4.87	0.52	0.46	0.37	0.39
South Carolina	9.05	8.35	4.15	4.58	0.53	0.46	0.35	0.37
South Dakota	9.45	8.35	4.01	4.39	0.54	0.46	0.34	0.35
Tennessee	8.60	8.35	4.48	5.02	0.51	0.46	0.38	0.40
Texas	9.51	8.35	3.95	4.32	0.54	0.46	0.33	0.34
Utah	9.70	8.35	3.88	4.22	0.55	0.46	0.32	0.34
Vermont	9.03	8.35	4.10	4.52	0.52	0.46	0.34	0.36

State	Volatile solids excretion rate (kg VS/day/1000 kg animal mass)				Nitrogen excretion rate (kg VS/day/1000 kg animal mass)			
	Dairy cows	Dairy heifers	Feedlot steer	Feedlot heifers	Dairy cows	Dairy heifers	Feedlot steer	Feedlot heifers
Virginia	9.02	8.35	3.98	4.35	0.53	0.46	0.33	0.35
Washington	10.36	8.35	4.07	4.47	0.58	0.46	0.34	0.36
West Virginia	8.13	8.35	4.65	5.25	0.48	0.46	0.40	0.42
Wisconsin	9.34	8.35	3.95	4.31	0.54	0.46	0.33	0.34
Wyoming	9.29	8.35	4.17	4.61	0.53	0.46	0.35	0.37

TABLE JJ–4 TO SUBPART JJ OF PART 98—VOLATILE SOLIDS AND NITROGEN REMOVAL THROUGH SOLIDS SEPARATION

Type of solids separation	Volatile solids removal (decimal)	Nitrogen removal (decimal)
Gravity	0.60	0.60
Mechanical:		
Stationary Screen	0.20	0.10
Vibrating Screen	0.15	0.15
Screw Press	0.25	0.15
Centrifuge	0.50	0.25
Roller drum	0.25	0.15
Belt press/screen	0.50	0.30

Table JJ-5 to Subpart JJ of Part 98—Methane Conversion Factors

Manure Management System Component	MCFs by Average Annual Ambient Temperature (degrees C)																		
	Cool					Temperate											Warm		
	<10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	>28
Uncovered Anaerobic Lagoon	66%	68%	70%	71%	73%	74%	75%	76%	77%	77%	78%	78%	78%	79%	79%	79%	79%	80%	80%
Liquid/slurry (with crust cover)	10%	11%	13%	14%	15%	17%	18%	20%	22%	24%	26%	29%	31%	34%	37%	41%	44%	48%	50%
Liquid/slurry (w/o crust cover)	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	80%
Storage pits <1 month	3.0%					3.0%											30.0%		
Storage pits >1 month	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	80%
Solid manure storage	2.0%					4.0%											5.0%		
Dry lots (including feedlots)	1.0%					1.5%											2.0%		
High-rise houses for poultry production (without litter)	1.5%					1.5%											1.5%		
Poultry production with litter	1.5%					1.5%											1.5%		
Deep bedding systems for cattle and swine(<1 month)	3.0%					3.0%											30.0%		
Deep bedding systems for cattle and swine (>1 month)	17%	19%	20%	22%	25%	27%	29%	32%	35%	39%	42%	46%	50%	55%	60%	65%	71%	78%	80%
Manure Composting - In Vessel	0.5%					0.5%											0.5%		
Manure Composting - Static Pile	0.5%					0.5%											0.5%		
Manure Composting-Extensive/ Passive	0.5%					1.0%											1.5%		
Manure Composting-Intensive	0.5%					1.0%											1.5%		
Aerobic Treatment	0.0%					0.0%											0.0%		

TABLE JJ–6 TO SUBPART JJ OF PART 98—COLLECTION EFFICIENCIES OF ANAEROBIC DIGESTERS

Anaerobic digester type	Cover type	Methane collection efficiency
Covered anaerobic lagoon (biogas capture)	Bank to bank, impermeable	0.975
	Modular, impermeable	0.70
Complete mix, fixed film, or plug flow digester	Enclosed Vessel	0.99

TABLE JJ–7 TO SUBPART JJ OF PART 98—NITROUS OXIDE EMISSION FACTORS (KG N_2O–N/KG KJDL N)

Manure management system component	N_2O emission factor
Uncovered anaerobic lagoon	0
Liquid/Slurry (with crust cover)	0.005
Liquid/Slurry (without crust cover)	0
Storage pits	0.002
Digesters	0
Solid manure storage	0.005
Dry lots (including feedlots)	0.02
High-rise house for poultry (poultry without litter)	0.001
Poultry production with litter	0.001
Deep bedding for cattle and swine (active mix)	0.07
Deep bedding for cattle and swine (no mix)	0.01
Manure Composting (in vessel)	0.006
Manure Composting (intensive)	0.1
Manure Composting (passive)	0.01
Manure Composting (static)	0.006
Aerobic Treatment (forced aeration)	0.005
Aerobic Treatment (natural aeration)	0.01

Subpart KK [Reserved]

Subpart LL—Suppliers of Coal-based Liquid Fuels

§ 98.380 Definition of the source category.

This source category consists of producers, importers, and exporters of products listed in Table MM–1 of subpart MM that are coal-based (coal-to-liquid products).

(a) A producer is the owner or operator of a coal-to-liquids facility. A coal-to-liquids facility is any facility engaged in converting coal into liquid products using a process involving conversion of coal into gas and then into liquids (e.g., Fischer-Tropsch) or conversion of coal directly into liquids (i.e., direct liquefaction).

(b) An importer or exporter shall have the same meaning given in § 98.6.

§ 98.381 Reporting threshold.

Any supplier of coal-to-liquid products who meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.382 GHGs to report.

You must report the CO_2 emissions that would result from the complete combustion or oxidation of fossil-fuel products (besides coal or crude oil) that you produce, use as feedstock, import, or export during the calendar year. Additionally, producers must report CO_2 emissions that would result from the complete combustion or oxidation of any biomass co-processed with fossil fuel-based feedstocks.

§ 98.383 Calculating GHG emissions.

You must follow the calculation methodologies of § 98.393 as if they applied to the appropriate coal-to-liquid product supplier (i.e., calculation methodologies for refiners apply to producers of coal-to-liquid products and calculation methodologies for importers and exporters of petroleum products apply to importers and exporters of coal-to-liquid products).

(a) In calculation methodologies in § 98.393 for petroleum products or petroleum-based products, suppliers of coal-to-liquid products shall also include coal-to-liquid products.

(b) In calculation methodologies in § 98.393 for non-crude feedstocks or non-crude petroleum feedstocks, producers of coal-to-liquid products shall also include coal-to-liquid products that enter the facility to be further processed or otherwise used on site.

(c) In calculation methodologies in § 98.393 for petroleum feedstocks, suppliers of coal-to-liquid products shall also include coal and coal-to-liquid products that enter the facility to be further processed or otherwise used on site.

§ 98.384 Monitoring and QA/QC requirements.

You must follow the monitoring and QA/QC requirements in § 98.394 as if they applied to the appropriate coal-to-liquid product supplier. Any monitoring and QA/QC requirement for petroleum products in § 98.394 also applies to coal-to-liquid products.

§ 98.385 Procedures for estimating missing data.

You must follow the procedures for estimating missing data in § 98.395 as if they applied to the appropriate coal-to-liquid product supplier. Any procedure for estimating missing data for petroleum products in § 98.395 also applies to coal-to-liquid products.

§98.386 Data reporting requirements.

In addition to the information required by §98.3(c), the following requirements apply:

(a) Producers shall report the following information for each coal-to-liquid facility:

(1) [Reserved]

(2) For each product listed in Table MM–1 of subpart MM of this part that enters the coal-to-liquid facility to be further processed or otherwise used on site, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each feedstock reported in paragraph (a)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(2) of this section that is fossil fuel-based (excluding any denaturant that may be present in any ethanol product).

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(2) of this section.

(5) [Reserved]

(6) For each product (leaving the coal-to-liquid facility) listed in Table MM–1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product. Those products that enter the facility, but are not reported in (a)(2), shall not be reported under this paragraph.

(7) For each product reported in paragraph (a)(6) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(6) of this section that is fossil fuel-based (excluding any denaturant that may be present in any ethanol product).

(8) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(6) of this section.

(9) For every feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of subpart MM of this part was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons CO_2 per barrel or per metric ton of product.

(10) For every non-solid feedstock reported in paragraph (a)(2) of this section for which Calculation Methodology 2 of subpart MM of this part was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(11) For every product reported in paragraph (a)(6) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to §98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons CO_2 per barrel or metric ton of product.

(12) For every non-solid product reported in paragraph (a)(6) of this section for which Calculation Method 2 of subpart MM of this part was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(13) [Reserved]

(14) For each specific type of biomass that enters the coal-to-liquid facility to be co-processed with fossil fuel-based feedstock to produce a product reported in paragraph (a)(6) of this section, report the annual quantity in metric tons or barrels.

(15) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (a)(14) of this section.

(16) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each feedstock reported in paragraph (a)(2) of this section that were calculated according to § 98.393(b) or (h).

(17) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each product (leaving the coal-to-liquid facility) reported in paragraph (a)(6) of this section that were calculated according to § 98.393(a) or (h).

(18) Annual CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with fossil fuel-based feedstocks reported in paragraph (a)(14) of this section, calculated according to § 98.393(c).

(19) Annual CO_2 emissions that would result from the complete combustion or oxidation of all products, calculated according to § 98.393(d).

(20) Annual quantity of bulk NGLs in metric tons or barrels received for processing during the reporting year.

(b) In addition to the information required by § 98.3(c), each importer shall report all of the following information at the corporate level:

(1) [Reserved]

(2) For each product listed in Table MM–1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product as listed in Table MM–1 of subpart MM of this part.

(3) For each product reported in paragraph (b)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (b)(2) of this section that is fossil fuel-based (excluding any denaturant that may be present in any ethanol product).

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (b)(2) of this section.

(5) For each product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart used was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c)

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons per barrel or per metric ton of product.

(6) For each non-solid product reported in paragraph (b)(2) of this section for which Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each imported product reported in paragraph (b)(2) of this section, calculated according to § 98.393(a).

(8) The total sum of CO_2 emissions that would result from the complete combustion or oxidation of all imported products, calculated according to § 98.393(e).

(c) In addition to the information required by § 98.3(c), each exporter shall report all of the following information at the corporate level:

(1) [Reserved]

(2) For each product listed in table MM–1 of subpart MM of this part, report the total annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each product reported in paragraph (c)(2) of this section that was produced by blending a fossil fuel-based product with a biomass-based product, report the percent of the volume reported in paragraph (c)(2) of this section that is fossil fuel-based (excluding any denaturant that may be present in any ethanol product).

(4) Each standard method or other industry standard practice used to measure each quantity reported in paragraph (c)(2) of this section.

(5) For each product reported in paragraph (c)(2) of this section for which

Calculation Methodology 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons CO_2 per barrel or per metric ton of product.

(6) For each non-solid product reported in paragraph (c)(2) of this section for which Calculation Methodology 2 of this subpart used was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each exported product reported in paragraph (c)(2) of this section, calculated according to § 98.393(a).

(8) Total sum of CO_2 emissions that would result from the complete combustion or oxidation of all exported products, calculated according to § 98.393(e).

(d) *Blended feedstock and products.* (1) Producers, exporters, and importers must report the following information for each blended product and feedstock where emissions were calculated according to § 98.393(i):

(i) Volume or mass of each blending component.

(ii) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each blended feedstock or product, using Equation MM–12 or Equation MM–13 of § 98.393.

(iii) Whether it is a blended feedstock or a blended product.

(2) For a product that enters the facility to be further refined or otherwise used on site that is a blended feedstock, producers must meet the reporting requirements of paragraph (a)(2) of this section by reflecting the individual components of the blended feedstock.

(3) For a product that is produced, imported, or exported that is a blended product, producers, importers, and exporters must meet the reporting requirements of paragraphs (a)(6), (b)(2), and (c)(2) of this section, as applicable, by reflecting the individual components of the blended product.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66475, Oct. 28, 2010; 78 FR 71972, Nov. 29, 2013]

§ 98.387 Records that must be retained.

You must retain records according to the requirements in § 98.397 as if they applied to the appropriate coal-to-liquid product supplier (e.g., retaining copies of all reports submitted to EPA under § 98.386 and records to support information contained in those reports). Any records for petroleum products that are required to be retained in § 98.397 are also required for coal-to-liquid products.

§ 98.388 Definitions.

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

Subpart MM—Suppliers of Petroleum Products

§ 98.390 Definition of the source category.

This source category consists of petroleum refineries and importers and exporters of petroleum products and natural gas liquids as listed in Table MM–1 of this subpart.

(a) A petroleum refinery for the purpose of this subpart is any facility engaged in producing petroleum products through the distillation of crude oil.

(b) A refiner is the owner or operator of a petroleum refinery.

(c) Importer has the same meaning given in § 98.6 and includes any entity that imports petroleum products or natural gas liquids as listed in Table MM–1 of this subpart. Any blender or refiner of refined or semi-refined petroleum products shall be considered an importer if it otherwise satisfies the aforementioned definition.

(d) Exporter has the same meaning given in § 98.6 and includes any entity that exports petroleum products or natural gas liquids as listed in Table MM–1 of this subpart. Any blender or refiner of refined or semi-refined petroleum products shall be considered an exporter if it otherwise satisfies the aforementioned definition.

§ 98.391 Reporting threshold.

Any supplier of petroleum products who meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.392 GHGs To report.

Suppliers of petroleum products must report the CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product and natural gas liquid produced, used as feedstock, imported, or exported during the calendar year. Additionally, refiners must report CO_2 emissions that would result from the complete combustion or oxidation of any biomass co-processed with petroleum feedstocks.

§ 98.393 Calculating GHG emissions.

(a) *Calculation for individual products produced, imported, or exported.* (1) Except as provided in paragraphs (h) and (i) of this section, any refiner, importer, or exporter shall calculate CO_2 emissions from each individual petroleum product and natural gas liquid using Equation MM–1 of this section.

$$CO_{2i} = Product_i \star EF_i \qquad \text{(Eq. MM-1)}$$

Where:

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid "i" (metric tons).

$Product_i$ = Annual volume of product "i" produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate, and excludes products that entered the refinery but are not reported under § 98.396(a)(2). For natural gas liquids, volumes shall reflect the individual components of the product as listed in Table MM–1 to subpart MM.

EF_i = Product-specific CO_2 emission factor (metric tons CO_2 per barrel).

(2) In the event that an individual petroleum product is produced as a solid rather than liquid any refiner, importer, or exporter shall calculate CO_2 emissions using Equation MM–1 of this section.

Where:

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product "i" (metric tons).

$Product_i$ = Annual mass of product "i" produced, imported, or exported by the reporting party (metric tons). For refiners, this mass only includes products ex refinery gate, and excludes products that entered the refinery but are not reported under § 98.396(a)(2).

EF_i = Product-specific CO_2 emission factor (metric tons CO_2 per metric ton of product).

(b) *Calculation for individual products that enter a refinery as a non-crude feedstock.* (1) Except as provided in paragraphs (h) and (i) of this section, any refiner shall calculate CO_2 emissions from each non-crude feedstock using Equation MM–2 of this section.

$$CO_{2j} = Feedstock_j \star EF_j \qquad \text{(Eq. MM-2)}$$

Where:

CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).

$Feedstock_j$ = Annual volume of a petroleum product or natural gas liquid "j" that enters the refinery to be further refined or otherwise used on site (barrels). For natural gas liquids, volumes shall reflect the individual components of the product as listed in table MM–1 of this subpart.

EF_j = Feedstock-specific CO_2 emission factor (metric tons CO_2 per barrel).

(2) In the event that a non-crude feedstock enters a refinery as a solid rather than liquid, the refiner shall calculate CO_2 emissions using Equation MM–2 of this section.

Where:

CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).

$Feedstock_j$ = Annual mass of a petroleum product "j" that enters the refinery to be further refined or otherwise used on site (metric tons).

EF_j = Feedstock-specific CO_2 emission factor (metric tons CO_2 per metric ton of feedstock).

(c) *Calculation for biomass co-processed with petroleum feedstocks.* (1) Refiners shall calculate CO_2 emissions from each type of biomass that enters a refinery and is co-processed with petroleum feedstocks using Equation MM–3 of this section.

$$CO_{2m} = Biomass_m \star EF_m \qquad \text{(Eq. MM-3)}$$

Where:

CO_{2m} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each type of biomass "m" (metric tons).

$Biomass_m$ = Annual volume of a specific type of biomass that enters the refinery and is co-processed with petroleum feedstocks to produce a petroleum product reported under paragraph (a) of this section (barrels).

EF_m = Biomass-specific CO_2 emission factor (metric tons CO_2 per barrel).

(2) In the event that biomass enters a refinery as a solid rather than liquid and is co-processed with petroleum feedstocks, the refiner shall calculate CO_2 emissions from each type of biomass using Equation MM–3 of this section.

Where:

CO_{2m} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each type of biomass "m" (metric tons).

$Biomass_m$ = Total annual mass of a specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported under paragraph (a) of this section (metric tons).

EF_m = Biomass-specific CO_2 emission factor (metric tons CO_2 per metric ton of biomass).

(d) *Summary calculation for refinery products.* Refiners shall calculate annual CO_2 emissions from all products using Equation MM–4 of this section.

$$CO_{2r} = \sum\left(CO_{2i}\right) - \sum\left(CO_{2j}\right) - \sum\left(CO_{2m}\right) \qquad \text{(Eq. MM-4)}$$

Where:

CO_{2r} = Annual CO_2 emissions that would result from the complete combustion or oxidation of all petroleum products and natural gas liquids (ex refinery gate) minus non-crude feedstocks and any biomass to be co-processed with petroleum feedstocks.

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid "i" (metric tons).

CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock "j" (metric tons).

CO_{2m} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each type of biomass "m" (metric tons).

(e) *Summary calculation for importer and exporter products.* Importers and exporters shall calculate annual CO_2 emissions from all petroleum products and natural gas liquids imported or exported, respectively, using Equations MM–1 and MM–5 of this section.

$$CO_{2x} = \sum\left(CO_{2i}\right) \qquad \text{(Eq. MM-5)}$$

Where:

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product or natural gas liquid "i" (metric tons).

CO_{2x} = Annual CO_2 emissions that would result from the complete combustion or oxidation of all petroleum products and natural gas liquids.

(f) *Emission factors for petroleum products and natural gas liquids.* The emission factor ($EF_{i,j}$) for each petroleum product and natural gas liquid shall be determined using either of the calculation methods described in paragraphs (f)(1) or (f)(2) of this section. The same calculation method must be used for the entire quantity of the product for the reporting year. For refiners, the quantity of a product that enters a refinery (i.e., a non-crude feedstock) is considered separate from the quantity of a product ex refinery gate.

(1) *Calculation Method 1.* To determine the emission factor (i.e., EF_i in Equation MM–1) for solid products, multiply the default carbon share factor (i.e., percent carbon by mass) in column B of Table MM–1 to this subpart for the appropriate product by 44/

12. For all other products, use the default CO_2 emission factor listed in column C of Table MM–1 of this subpart for the appropriate product.

(2) *Calculation Method 2.* (i) For solid products, develop emission factors according to Equation MM–6 of this section using a value of 1 for density and direct measurements of carbon share according to methods set forth in § 98.394(c). For all other products, develop emission factors according to Equation MM–6 of this section using direct measurements of density and carbon share according to methods set forth in § 98.394(c).

$$EF_{i,j} = \text{Density} \star \text{Carbon Share} \star (44/12) \qquad \text{(Eq. MM-6)}$$

Where:

$EF_{i,j}$ = Emission factor of the petroleum product or natural gas liquid (metric tons CO_2 per barrel or per metric ton of product).

Density = Density of the petroleum product or natural gas liquid (metric tons per barrel for non-solid products, 1 for solid products).

Carbon share = Percent of total mass that carbon represents in the petroleum product or natural gas liquid, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

44/12 = Conversion factor for carbon to carbon dioxide.

(ii) If you use a standard method that involves gas chromatography to determine the percent mass of each component in a product, calculate the product's carbon share using Equation MM–7 of this section.

$$\text{Carbon Share} = \sum \left(\%\text{Composition}_{i \ldots n} \star \%\text{Mass}_{i \ldots n} \right) \qquad \text{(Eq. MM-7)}$$

Where:

Carbon Share = Percent of total mass that carbon represents in the petroleum product or natural gas liquid.

%Composition i* * *n = Percent of total mass that each molecular component in the petroleum product or natural gas liquid represents as determined by the procedures in the selected standard method.

$\%Mass_{i* * *n}$ = Percent of total mass that carbon represents in each molecular component of the petroleum product or natural gas liquid.

(g) *Emission factors for biomass co-processed with petroleum feedstocks.* Refiners shall use the most appropriate default CO_2 emission factor (EF_m) for biomass in Table MM–2 of this subpart to calculate CO_2 emissions in paragraph (c) of this section.

(h) *Special procedures for blended biomass-based fuels.* In the event that some portion of a petroleum product is biomass-based and was not derived by co-processing biomass and petroleum feedstocks together (i.e., the petroleum product was produced by blending a petroleum-based product with a biomass-based fuel), the reporting party shall calculate emissions for the petroleum product according to one of the methods in paragraphs (h)(1) through (h)(4) of this section, as appropriate.

(1) A reporter using Calculation Method 1 to determine the emission factor of a petroleum product shall calculate the CO_2 emissions associated with that product using Equation MM–8 of this section in place of Equation MM–1 of this section.

$$CO_{2i} = \text{Product}_i \star EF_i \star \%Vol_i \qquad \text{(Eq. MM-8)}$$

Where:

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each petroleum product ''i'' (metric tons).

$Product_i$ = Annual volume of each petroleum product ''i'' produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate.

EF_i = Petroleum product-specific CO_2 emission factor (metric tons CO_2 per barrel) from Table MM–1 of this subpart.

$\%Vol_i$ = Percent volume of product ''i'' that is petroleum-based, not including any denaturant that may be present in any ethanol product, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

(2) A refinery using Calculation Method 1 of this subpart to determine the emission factor of a non-crude petroleum feedstock shall calculate the CO_2 emissions associated with that feedstock using Equation MM–9 of this section in place of Equation MM–2 of this section.

$$CO_{2j} = Feedstock_j * EF_j * \%Vol_j \qquad \text{(Eq. MM-9)}$$

Where:

CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock ''j'' (metric tons).

$Feedstock_j$ = Annual volume of each petroleum product ''j'' that enters the refinery as a feedstock to be further refined or otherwise used on site (barrels).

EF_j = Non-crude petroleum feedstock-specific CO_2 emission factor (metric tons CO_2 per barrel).

$\%Vol_j$ = Percent volume of feedstock ''j'' that is petroleum-based, not including any denaturant that may be present in any ethanol product, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

(3) *Calculation Method 2 procedures for products.* (i) A reporter using Calculation Method 2 of this subpart to determine the emission factor of a petroleum product that does not contain denatured ethanol must calculate the CO_2 emissions associated with that product using Equation MM–10 of this section in place of Equation MM–1 of this section.

$$CO_{2i} = \left(Product_i * \ EF_i\right) - \left(Product_i * \ EF_m * \ \%Vol_m\right) \qquad \text{(Eq. MM-10)}$$

where:

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each product ''i'' (metric tons).

$Product_i$ = Annual volume of each petroleum product ''i'' produced, imported, or exported by the reporting party (barrels). For refiners, this volume only includes products ex refinery gate.

EF_i = Product-specific CO_2 emission factor (metric tons CO_2 per barrel).

EF_m = Default CO_2 emission factor from Table MM–2 to subpart MM that most closely represents the component of product ''i'' that is biomass-based.

$\%Vol_m$ = Percent volume of petroleum product ''i'' that is biomass-based, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

(ii) In the event that a petroleum product contains denatured ethanol, importers and exporters must follow Calculation Method 1 procedures in paragraph (h)(1) of this section; and refineries must sample the petroleum portion of the blended biomass-based fuel prior to blending and calculate CO_2 emissions using Equation MM–10a of this section.

$$CO_{2i} = Product_p * EF_i \qquad \text{(Eq. MM-10a)}$$

where:

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each biomass-blended fuel ''i'' (metric tons).

$Product_p$ = Annual volume of the petroleum-based portion of each biomass blended fuel ''i'' produced by the refiner (barrels).

EF_i = Petroleum product-specific CO_2 emission factor (metric tons CO_2 per barrel).

(4) *Calculation Method 2 procedures for non-crude feedstocks.* (i) A refiner using Calculation Method 2 of this subpart to determine the emission factor of a non-crude petroleum feedstock that does not contain denatured ethanol must calculate the CO_2 emissions associated with that feedstock using Equation MM–11 of this section in place of Equation MM–2 of this section.

$$CO_{2j} = \left(\text{Feedstock}_j * EF_j\right) - \left(\text{Feedstock}_j * EF_m * \%\text{Vol}_m\right) \qquad \text{(Eq. MM-11)}$$

where:

CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of each non-crude feedstock ‘‘j’’ (metric tons).

Feedstock_j = Annual volume of each petroleum product ‘‘j’’ that enters the refinery to be further refined or otherwise used on site (barrels).

EF_j = Feedstock-specific CO_2 emission factor (metric tons CO_2 per barrel).

EF_m = Default CO_2 emission factor from Table MM–2 to subpart MM that most closely represents the component of petroleum product ‘‘j’’ that is biomass-based.

$\%\text{Vol}_m$ = Percent volume of non-crude feedstock ‘‘j’’ that is biomass-based, expressed as a fraction (e.g., 75% would be expressed as 0.75 in the above equation).

(ii) In the event that a non-crude feedstock contains denatured ethanol, refiners must follow Calculation Method 1 procedures in paragraph (h)(2) of this section.

(i) *Optional procedures for blended products that do not contain biomass.* (1) In the event that a reporter produces, imports, or exports a blended product that does not include biomass, the reporter may calculate emissions for the blended product according to the method in paragraph (i)(2) of this section. In the event that a refiner receives a blended non-crude feedstock that does not include biomass, the refiner may calculate emission for the blended non-crude feedstock according to the method in paragraph (i)(3) of this section. The procedures in this section may be used only if all of the following criteria are met:

(i) The reporter knows the relative proportion of each component of the blend (i.e., the mass or volume percentage).

(ii) Each component of blended product ‘‘i’’ or blended non-crude feedstock ‘‘j’’ meets the strict definition of a product listed in Table MM–1 to subpart MM.

(iii) The blended product or non-crude feedstock is not comprised entirely of natural gas liquids.

(iv) The reporter uses Calculation Method 1.

(v) Solid components are blended only with other solid components.

(2) The reporter must calculate emissions for the blended product using Equation MM–12 of this section in place of Equation MM–1 of this section.

$$CO_{2i} = \sum\left[\mathit{Blending\ Component}_{i\ldots n} * EF_{i\ldots n}\right] \qquad \text{(Eq. MM-12)}$$

where:

CO_{2i} = Annual CO_2 emissions that would result from the complete combustion or oxidation of a blended product ‘‘i’’ (metric tons).

$\text{Blending Component}_{i\ldots n}$ = Annual volume or mass of each blending component that is blended (barrels or metric tons).

$EF_{i\ldots n}$ = CO_2 emission factors specific to each blending component (metric tons CO_2 per barrel or per metric ton of product).

n = Number of blending components blended into blended product ‘‘i’’.

(3) For refineries, the reporter must calculate emissions for the blended non-crude feedstock using Equation

MM–13 of this section in place of Equation MM–2 of this section.

$$CO_{2i} = \sum \left[\mathit{Blending\ Component}_{i\ldots n} * EF_{i\ldots n} \right] \qquad \text{(Eq. MM-13)}$$

where:

CO_{2j} = Annual CO_2 emissions that would result from the complete combustion or oxidation of a blended non-crude feedstock ‘‘j’’ (metric tons).

Blending $\text{Component}_{i\ldots n}$ = Annual volume or mass of each blending component that is blended (barrels or metric tons).

$EF_{i\ldots n}$ = CO_2 emission factors specific to each blending component (metric tons CO_2 per barrel or per metric ton of product).

n = Number of blending components blended into blended non-crude feedstock ‘‘j’’.

(4) For refineries, if a blending component ‘‘k’’ used in paragraph (i)(2) of this section enters the refinery before blending as non-crude feedstock:

(i) The emissions that would result from the complete combustion or oxidation of non-crude feedstock ‘‘k’’ must still be calculated separately using Equation MM–2 of this section and applied in Equation MM–4 of this section.

(ii) The quantity of blending component ‘‘k’’ applied in Equation MM–12 of this section and the quantity of non-crude feedstock ‘‘k’’ applied in Equation MM–2 of this section must be determined using the same method or practice.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66475, Oct. 28, 2010; 78 FR 71973, Nov. 29, 2013]

§ 98.394 Monitoring and QA/QC requirements.

(a) *Determination of quantity.* (1) The quantity of petroleum products, natural gas liquids, and biomass, shall be determined as follows:

(i) Where an appropriate standard method published by a consensus-based standards organization exists, such a method shall be used. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, industry standard practices shall be followed.

(iii) For products that are liquid at 60 degrees Fahrenheit and one standard atmosphere, all measurements of quantity shall be temperature-adjusted and pressure-adjusted to these conditions. For all other products, reporters shall use appropriate standard conditions specified in the standard method; if temperature and pressure conditions are not specified in the standard method or if a reporter uses an industry standard practice to determine quantity, the reporter shall use appropriate standard conditions according to established industry practices.

(2) All measurement equipment (including, but not limited to, flow meters and tank gauges) used for compliance with this subpart shall be appropriate for the standard method or industry standard practice followed under paragraph (a)(1)(i) or (a)(1)(ii) of this section.

(3) The annual quantity of crude oil received shall be determined according to one of the following methods. You may use an appropriate standard method published by a consensus-based standards organization or you may use an industry standard practice.

(b) *Equipment Calibration.* (1) All measurement equipment shall be calibrated prior to its first use for reporting under this subpart, using an appropriate standard method published by a consensus based standards organization or according to the equipment manufacturer’s directions.

(2) Measurement equipment shall be recalibrated at the minimum frequency specified by the standard method used

or by the equipment manufacturer's directions.

(3) For units and processes that operate continuously with infrequent outages, it may not be possible to complete the calibration of a flow meter or other measurement device without disrupting normal process operation. In such cases, the owner or operator may postpone the calibration until the next scheduled maintenance outage. The best available information from company records may be used in the interim. Such postponements shall be documented in the monitoring plan that is required under § 98.3(g)(5).

(c) *Procedures for Calculation Method 2 of this subpart.* (1) Reporting parties shall collect one sample of each petroleum product or natural gas liquid on any day of each calendar month of the reporting year in which the quantity of that product was measured in accordance with the requirements of this subpart. For example, if a given product was measured as entering the refinery continuously throughout the reporting year, twelve samples of that product shall be collected over the reporting year, one on any day of each calendar month of that year. If a given product was only measured from April 15 through June 10 of the reporting year, a refiner would collect three samples during that year, one during each of the calendar months of April, May and June on a day when the product was measured as either entering or exiting the refinery. Each sample shall be collected using an appropriate standard method published by a consensus-based standards organization.

(2) Mixing and handling of samples shall be performed using an appropriate standard method published by a consensus-based standards organization.

(3) Density measurement.

(i) For all products that are not solid, reporters shall test for density using an appropriate standard method published by a consensus-based standards organization.

(ii) The density value for a given petroleum product shall be generated by either making a physical composite of all of the samples collected for the reporting year and testing that single sample or by measuring the individual samples throughout the year and defining the representative density value for the sample set by numerical means, i.e., a mathematical composite. If a physical composite is chosen as the option to obtain the density value, the reporter shall submit each of the individual samples collected during the reporting year to the laboratory responsible for generating the composite sample.

(iii) For physical composites, the reporter shall handle the individual samples and the laboratory shall mix them in accordance with an appropriate standard method published by a consensus-based standards organization.

(iv) All measurements of density shall be temperature-adjusted and pressure-adjusted to the conditions assumed for determining the quantities of the product reported under this subpart.

(4) Carbon share measurement.

(i) Reporters shall test for carbon share using an appropriate standard method published by a consensus-based standards organization.

(ii) If a standard method that involves gas chromatography is used to determine the percent mass of each component in a product, the molecular formula for each component shall be obtained from the information provided in the standard method and the atomic mass of each element in a given molecular component shall be obtained from the periodic table of the elements.

(iii) The carbon share value for a given petroleum product shall be generated by either making a physical composite of all of the samples collected for the reporting year and testing that single sample or by measuring the individual samples throughout the year and defining the representative carbon share value for the sample set by numerical means, i.e., a mathematical composite. If a physical composite is chosen as the option to obtain the carbon share value, the reporter shall submit each of the individual samples collected during the reporting year to the laboratory responsible for generating the composite sample.

(iv) For physical composites, the reporter shall handle the individual samples and the laboratory shall mix them in accordance with an appropriate standard method published by a consensus-based standards organization.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66477, Oct. 28, 2010; 78 FR 71972, Nov. 29, 2013]

§ 98.395 Procedures for estimating missing data.

(a) *Determination of quantity*. Whenever the quality assurance procedures in § 98.394(a) cannot be followed to measure the quantity of one or more petroleum products, natural gas liquids, types of biomass, feedstocks, or crude oil during any period (e.g., if a meter malfunctions), the following missing data procedures shall be used:

(1) For quantities of a product that are purchased or sold, a period of missing data shall be substituted using a reporter's established procedures for billing purposes in that period as agreed to by the party selling or purchasing the product.

(2) For quantities of a product that are not purchased or sold but of which the custody is transferred, a period of missing data shall be substituted using a reporter's established procedures for tracking purposes in that period as agreed to by the party involved in custody transfer of the product.

(b) *Determination of emission factor*. Whenever any of the procedures in § 98.394(c) cannot be followed to develop an emission factor for any reason, Calculation Method 1 of this subpart must be used in place of Calculation Method 2 of this subpart for the entire reporting year.

(c) *Determination of API gravity and sulfur content of crude oil*. For missing data on sulfur content or API gravity, the substitute data value shall be the arithmetic average of the quality-assured values of API gravity or sulfur content in the batch preceding and the batch immediately following the missing data incident. If no quality-assured data are available prior to the missing data incident, the substitute data value shall be the first quality-assured values for API gravity and sulfur content obtained from the batch after the missing data period.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71973, Nov. 29, 2013]

§ 98.396 Data reporting requirements.

In addition to the information required by § 98.3(c), the following requirements apply:

(a) Refiners shall report the following information for each facility:

(1) [Reserved]

(2) For each petroleum product or natural gas liquid listed in Table MM–1 of this subpart that enters the refinery to be further refined or otherwise used on site, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each feedstock reported in paragraph (a)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(2) of this section that is petroleum-based (excluding any denaturant that may be present in any ethanol product).

(4)–(5) [Reserved]

(6) For each petroleum product and natural gas liquid (ex refinery gate) listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product. Petroleum products and natural gas liquids that enter the refinery, but are not reported in (a)(2), shall not be reported under this paragraph.

(7) For each product reported in paragraph (a)(6) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (a)(6) of this section that is petroleum-based (excluding any denaturant that may be present in any ethanol product).

(8) [Reserved]

(9) For every feedstock reported in paragraph (a)(2) of this section for which Calculation Method 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c)

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons CO_2 per barrel or per metric ton of product.

(10) For every non-solid feedstock reported in paragraph (a)(2) of this section for which Calculation Method 2 of this subpart was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(11) For every petroleum product and natural gas liquid reported in paragraph (a)(6) of this section for which Calculation Method 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons CO_2 per barrel or per metric ton of product.

(12) For every non-solid petroleum product and natural gas liquid reported in paragraph (a)(6) for which Calculation Method 2 was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(13) [Reserved]

(14) For each specific type of biomass that enters the refinery to be co-processed with petroleum feedstocks to produce a petroleum product reported in paragraph (a)(6) of this section, report the annual quantity in metric tons or barrels.

(15) [Reserved]

(16) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each petroleum product and natural gas liquid (ex refinery gate) reported in paragraph (a)(6) of this section that were calculated according to § 98.393(a) or (h).

(17) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each feedstock reported in paragraph (a)(2) of this section that were calculated according to § 98.393(b) or (h).

(18) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each type of biomass feedstock co-processed with petroleum feedstocks reported in paragraph (a)(14) of this section, calculated according to § 98.393(c).

(19) The sum of CO_2 emissions that would result from the complete combustion or oxidation of all products, calculated according to § 98.393(d).

(20) For all crude oil that enters the refinery, report the annual quantity in barrels.

(21) The quantity of bulk NGLs in metric tons or barrels received for processing during the reporting year. Report only quantities of bulk NGLs not reported in (a)(2) of this section.

(22) Volume of crude oil in barrels that you injected into a crude oil supply or reservoir.

(b) In addition to the information required by § 98.3(c), each importer shall report all of the following information at the corporate level:

(1) [Reserved]

(2) For each petroleum product and natural gas liquid listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each product reported in paragraph (b)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (b)(2) of this section that is petroleum-based (excluding any denaturant that may be present in any ethanol product).

(4) [Reserved]

(5) For each product reported in paragraph (b)(2) of this section for which Calculation Method 2 of this subpart used was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percent mass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons CO_2 per barrel or per metric ton of product.

(6) For each non-solid product reported in paragraph (b)(2) of this section for which Calculation Method 2 of this subpart was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each imported petroleum product and natural gas liquid reported in paragraph (b)(2) of this section, calculated according to § 98.393(a).

(8) The sum of CO_2 emissions that would result from the complete combustion oxidation of all imported products, calculated according to § 98.393(e).

(c) In addition to the information required by § 98.3(c), each exporter shall report all of the following information at the corporate level:

(1) [Reserved]

(2) For each petroleum product and natural gas liquid listed in Table MM–1 of this subpart, report the annual quantity in metric tons or barrels. For natural gas liquids, quantity shall reflect the individual components of the product.

(3) For each product reported in paragraph (c)(2) of this section that was produced by blending a petroleum-based product with a biomass-based product, report the percent of the volume reported in paragraph (c)(2) of this section that is petroleum based (excluding any denaturant that may be present in any ethanol product).

(4) [Reserved]

(5) For each product reported in paragraph (c)(2) of this section for which Calculation Method 2 of this subpart was used to determine an emissions factor, report:

(i) The number of samples collected according to § 98.394(c).

(ii) The sampling standard method used.

(iii) The carbon share test results in percentmass.

(iv) The standard method used to test carbon share.

(v) The calculated CO_2 emissions factor in metric tons CO_2 per barrel or per metric ton of product.

(6) For each non-solid product reported in paragraph (c)(2) of this section for which Calculation Method 2 of this subpart used was used to determine an emissions factor, report:

(i) The density test results in metric tons per barrel.

(ii) The standard method used to test density.

(7) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of for each exported petroleum product and natural gas liquid reported in paragraph (c)(2) of this section, calculated according to § 98.393(a).

(8) The sum of CO_2 emissions that would result from the complete combustion or oxidation of all exported products, calculated according to § 98.393(e).

(d) *Blended non-crude feedstock and products.* (1) Refineries, exporters, and importers must report the following information for each blended product and non-crude feedstock where emissions were calculated according to § 98.393(i):

(i) Volume or mass of each blending component.

(ii) The CO_2 emissions in metric tons that would result from the complete combustion or oxidation of each blended non-crude feedstock or product, using Equation MM–12 or Equation MM–13 of this section.

(iii) Whether it is a blended non-crude feedstock or a blended product.

(2) For a product that enters the refinery to be further refined or otherwise used on site that is a blended non-crude feedstock, refiners must meet the reporting requirements of paragraph (a)(2) of this section by reflecting the individual components of the blended non-crude feedstock.

(3) For a product that is produced, imported, or exported that is a blended product, refiners, importers, and exporters must meet the reporting requirements of paragraphs (a)(6), (b)(2), and (c)(2) of this section, as applicable,

by reflecting the individual components of the blended product.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66477, Oct. 28, 2010; 78 FR 71973, Nov. 29, 2013]

§ 98.397 Records that must be retained.

(a) All reporters shall retain copies of all reports submitted to EPA under § 98.396. In addition, all reporters shall maintain sufficient records to support information contained in those reports, including but not limited to information on the characteristics of their feedstocks and products.

(b) Reporters shall maintain records to support quantities that are reported under this subpart, including records documenting any estimations of missing data and the number of calendar days in the reporting year for which substitute data procedures were followed. For all reported quantities of petroleum products, natural gas liquids, and biomass, reporters shall maintain metering, gauging, and other records normally maintained in the course of business to document product and feedstock flows including the date of initial calibration and the frequency of recalibration for the measurement equipment used.

(c) Reporters shall retain laboratory reports, calculations and worksheets used to estimate the CO_2 emissions of the quantities of petroleum products, natural gas liquids, biomass, and feedstocks reported under this subpart.

(d) Reporters shall maintain laboratory reports, calculations and worksheets used in the measurement of density and carbon share for any petroleum product or natural gas liquid for which CO_2 emissions were calculated using Calculation Method 2.

(e) Estimates of missing data shall be documented and records maintained showing the calculations.

(f) Reporters described in this subpart shall also retain all records described in § 98.3(g).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66478, Oct. 28, 2010; 78 FR 71974, Nov. 29, 2013]

§ 98.398 Definitions.

Except as specified in this section, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Bulk NGLs for purposes of reporting under this subpart means mixtures of NGLs that are sold or delivered as undifferentiated product.

Natural Gas Liquids (NGLs) for the purposes of reporting under this subpart means hydrocarbons that are separated from natural gas as liquids through the process of absorption, condensation, adsorption, or other methods, and are sold or delivered as differentiated product. Generally, such liquids consist of ethane, propane, butanes, or pentanes plus.

[75 FR 66478, Oct. 28, 2010, as amended at 78 FR 71974, Nov. 29, 2013]

TABLE MM–1 TO SUBPART MM OF PART 98—DEFAULT FACTORS FOR PETROLEUM PRODUCTS AND NATURAL GAS LIQUIDS [1] [2]

Products	Column A: density (metric tons/bbl)	Column B: carbon share (% of mass)	Column C: emission factor (metric tons CO_2/bbl)
Finished Motor Gasoline			
Conventional—Summer			
Regular	0.1181	86.66	0.3753
Midgrade	0.1183	86.63	0.3758
Premium	0.1185	86.61	0.3763
Conventional—Winter			
Regular	0.1155	86.50	0.3663
Midgrade	0.1161	86.55	0.3684
Premium	0.1167	86.59	0.3705
Reformulated—Summer			
Regular	0.1167	86.13	0.3686
Midgrade	0.1165	86.07	0.3677
Premium	0.1164	86.00	0.3670

Products	Column A: density (metric tons/ bbl)	Column B: carbon share (% of mass)	Column C: emission factor (metric tons CO_2/bbl)
Reformulated—Winter			
Regular	0.1165	86.05	0.3676
Midgrade	0.1165	86.06	0.3676
Premium	0.1166	86.06	0.3679
Gasoline—Other	0.1185	86.61	0.3763
Blendstocks			
CBOB—Summer			
Regular	0.1181	86.66	0.3753
Midgrade	0.1183	86.63	0.3758
Premium	0.1185	86.61	0.3763
CBOB—Winter			
Regular	0.1155	86.50	0.3663
Midgrade	0.1161	86.55	0.3684
Premium	0.1167	86.59	0.3705
RBOB—Summer			
Regular	0.1167	86.13	0.3686
Midgrade	0.1165	86.07	0.3677
Premium	0.1164	86.00	0.3670
RBOB—Winter			
Regular	0.1165	86.05	0.3676
Midgrade	0.1165	86.06	0.3676
Premium	0.1166	86.06	0.3679
Blendstocks—Other	0.1185	86.61	0.3763
Oxygenates			
Methanol	0.1268	37.48	0.1743
GTBA	0.1257	64.82	0.2988
MTBE	0.1181	68.13	0.2950
ETBE	0.1182	70.53	0.3057
TAME	0.1229	70.53	0.3178
DIPE	0.1156	70.53	0.2990
Distillate Fuel Oil			
Distillate No. 1			
Ultra Low Sulfur	0.1346	86.40	0.4264
Low Sulfur	0.1346	86.40	0.4264
High Sulfur	0.1346	86.40	0.4264
Distillate No. 2			
Ultra Low Sulfur	0.1342	87.30	0.4296
Low Sulfur	0.1342	87.30	0.4296
High Sulfur	0.1342	87.30	0.4296
Distillate Fuel Oil No. 4	0.1452	86.47	0.4604
Residual Fuel Oil No. 5 (Navy Special)	0.1365	85.67	0.4288
Residual Fuel Oil No. 6 (a.k.a. Bunker C)	0.1528	84.67	0.4744
Kerosene-Type Jet Fuel	0.1294	86.30	0.4095
Kerosene	0.1346	86.40	0.4264
Diesel—Other	0.1452	86.47	0.4604
Petrochemical Feedstocks			
Naphthas (<401 °F)	0.1158	84.11	0.3571
Other Oils (>401 °F)	0.1390	87.30	0.4450
Unfinished Oils			
Heavy Gas Oils	0.1476	85.80	0.4643
Residuum	0.1622	85.70	0.5097
Other Petroleum Products and Natural Gas Liquids			
Aviation Gasoline	0.1120	85.00	0.3490
Special Naphthas	0.1222	84.76	0.3798
Lubricants	0.1428	85.80	0.4492
Waxes	0.1285	85.30	0.4019
Petroleum Coke	0.1818	92.28	0.6151
Asphalt and Road Oil	0.1634	83.47	0.5001
Still Gas	0.1405	77.70	0.4003

Products	Column A: density (metric tons/bbl)	Column B: carbon share (% of mass)	Column C: emission factor (metric tons CO_2/bbl)
Ethane[3]	0.0579	79.89	0.170
Ethylene[4]	0.0492	85.63	0.154
Propane[3]	0.0806	81.71	0.241
Propylene[3]	0.0827	85.63	0.260
Butane[3]	0.0928	82.66	0.281
Butylene[3]	0.0972	85.63	0.305
Isobutane[3]	0.0892	82.66	0.270
Isobutylene[3]	0.0949	85.63	0.298
Isobutylene	0.0936	85.63	0.2939
Pentanes Plus	0.1055	83.63	0.3235
Miscellaneous Products	0.1380	85.49	0.4326

[1] In the case of products blended with some portion of biomass-based fuel, the carbon share in Table MM–1 of this subpart represents only the petroleum-based components.

[2] Products that are derived entirely from biomass should not be reported, but products that were derived from both biomass and a petroleum product (i.e., co-processed) should be reported as the petroleum product that it most closely represents.

[3] The density and emission factors for components of LPG determined at 60 degrees Fahrenheit and saturation pressure (LPGs other than ethylene).

[4] The density and emission factor for ethylene determined at 41 degrees Fahrenheit and saturation pressure.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71975, Nov. 29, 2013]

TABLE MM–2 TO SUBPART MM OF PART 98—DEFAULT FACTORS FOR BIOMASS-BASED FUELS AND BIOMASS

Biomass-based fuel and biomass	Column A: Density (metric tons/bbl)	Column B: Carbon share (% of mass)	Column C: Emission factor (metric tons CO_2/bbl)
Ethanol (100%)	0.1267	52.14	0.2422
Biodiesel (100%, methyl ester)	0.1396	77.30	0.3957
Rendered Animal Fat	0.1333	76.19	0.3724
Vegetable Oil	0.1460	76.77	0.4110

Subpart NN—Suppliers of Natural Gas and Natural Gas Liquids

§ 98.400 Definition of the source category.

This supplier category consists of natural gas liquids fractionators and local natural gas distribution companies.

(a) Natural gas liquids fractionators are installations that fractionate natural gas liquids (NGLs) into their constituent liquid products or mixtures of products (ethane, propane, normal butane, isobutane or pentanes plus) for supply to downstream facilities.

(b) Local Distribution Companies (LDCs) are companies that own or operate distribution pipelines, not interstate pipelines or intrastate pipelines, that physically deliver natural gas to end users and that are within a single state that are regulated as separate operating companies by State public utility commissions or that operate as independent municipally-owned distribution systems. LDCs do not include pipelines (both interstate and intrastate) delivering natural gas directly to major industrial users and farm taps upstream of the local distribution company inlet.

(c) This supply category does not consist of the following facilities:

(1) Field gathering and boosting stations.

(2) Natural gas processing plants that separate NGLs from natural gas and produce bulk or y-grade NGLs but do not fractionate these NGLs into their constituent products.

(3) Facilities that meet the definition of refineries and report under subpart MM of this part.

(4) Facilities that meet the definition of petrochemical plants and report under subpart X of this part.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71975, Nov. 29, 2013]

§98.401 Reporting threshold.

Any supplier of natural gas and natural gas liquids that meets the requirements of §98.2(a)(4) must report GHG emissions.

§98.402 GHGs to report.

(a) NGL fractionators must report the CO_2 emissions that would result from the complete combustion or oxidation of the annual quantity of ethane, propane, normal butane, isobutane, and pentanes plus that is produced and sold or delivered to others.

(b) LDCs must report the CO_2 emissions that would result from the complete combustion or oxidation of the annual volumes of natural gas provided to end-users on their distribution systems.

§98.403 Calculating GHG emissions.

(a) LDCs and fractionators shall, for each individual product reported under this part, calculate the estimated CO_2 emissions that would result from the complete combustion or oxidation of the products supplied using either of Calculation Methodology 1 or 2 of this subpart:

(1) *Calculation Methodology 1.* NGL fractionators shall estimate CO_2 emissions that would result from the complete combustion or oxidation of the product(s) supplied using Equation NN–1 of this section. LDCs shall estimate CO_2 emissions that would result from the complete combustion or oxidation of the product received at the city gate using Equation NN–1. For each product, use the default value for higher heating value and CO_2 emission factor in Table NN–1 of this subpart. Alternatively, for each product, a reporter-specific higher heating value and CO_2 emission factor may be used, in place of one or both defaults provided they are developed using methods outlined in §98.404. For each product, you must use the same volume unit throughout the equation.

$$CO_{2i} = 1 \times 10^{-3} \star \sum Fuel_h \star HHV_h \star EF_h \qquad \text{(Eq. NN-1)}$$

Where:

CO_{2i} = Annual CO_2 mass emissions that would result from the combustion or oxidation of each product ''h'' for redelivery to all recipients (metric tons).

$Fuel_h$ = Total annual volume of product ''h'' supplied (volume per year, in thousand standard cubic feet (Mscf) for natural gas and bbl for NGLs).

HHV_h = Higher heating value of product ''h'' supplied (MMBtu/Mscf or MMBtu/bbl).

EF_h = CO_2 emission factor of product ''h'' (kg CO_2/MMBtu).

1×10^{-3} = Conversion factor from kilograms to metric tons (MT/kg).

(2) *Calculation Methodology 2.* NGL fractionators shall estimate CO_2 emissions that would result from the complete combustion or oxidation of the product(s) supplied using Equation NN–2 of this section. LDCs shall estimate CO_2 emissions that would result from the complete combustion or oxidation of the product received at the city gate using Equation NN–2. For each product, use the default CO_2 emission factor found in Table NN–2 of this subpart. Alternatively, for each product, a reporter-specific CO_2 emission factor may be used in place of the default factor, provided it is developed using methods outlined in §98.404. For each product, you must use the same volume unit throughout the equation.

$$CO_{2i} = \sum_h Fuel_h * EF_h \qquad \text{(Eq. NN-2)}$$

Where:

CO_{2i} = Annual CO_2 mass emissions that would result from the combustion or oxidation of each product ''h'' (metric tons)

$Fuel_h$ = Total annual volume of product ''h'' supplied (volume per year, in Mscf for natural gas and bbl for NGLs).

EF_h = CO_2 emission factor of product ''h'' (MT CO_2/bbl, or MT CO_2/Mscf)

(b) Each LDC shall follow the procedures below.

(1) For natural gas that is received for redelivery to downstream gas transmission pipelines and other local distribution companies, use Equation NN–

3 of this section and the default values for the CO_2 emission factors found in Table NN–2 of this subpart. Alternatively, reporter-specific CO_2 emission factors may be used, provided they are developed using methods outlined in § 98.404.

$$CO_{2j} = Fuel \star EF \qquad \text{(Eq. NN-3)}$$

Where:

CO_{2j} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas for redelivery to transmission pipelines or other LDCs (metric tons).

Fuel = Total annual volume of natural gas supplied (Mscf per year).

EF = Fuel-specific CO_2 emission factor (MT CO_2/Mscf).

(2)(i) For natural gas delivered to large end-users, use Equation NN–4 of this section and the default values for the CO_2 emission factors found in Table NN–2 of this subpart. A large end-user means any end-user facility receiving greater than or equal to 460,000 Mscf of natural gas per year. If the LDC does not know the total quantity of gas delivered to the end-user facility based on readily available information in the LDCs possession, then large end-user means any single meter at an end-user facility to which the LDC delivers equal to or greater than 460,000 Mscf per year.

(ii) Alternatively, reporter-specific CO_2 emission factors may be used, provided they are developed using methods outlined in § 98.404.

$$CO_{2k} = Fuel \star EF \qquad \text{(Eq. NN-4)}$$

Where:

CO_{2k} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas delivered to each large end-user k, as defined in paragraph (b)(2)(i) of this section (metric tons).

Fuel = Total annual volume of natural gas supplied to each large end-user k, as defined in paragraph (b)(2)(i) of this section (Mscf per year).

EF = Fuel-specific CO_2 emission factor (MT CO_2/Mscf).

(3) For the net change in natural gas stored on system by the LDC during the reporting year, use Equation NN–5a of this section. For natural gas that is received by means other than through the city gate, and is not otherwise accounted for by Equation NN–1 or NN–2 of this section, use Equation NN–5b of this section.

(i) For natural gas received by the LDC that is injected into on-system storage, and/or liquefied and stored, and for gas removed from storage and used for deliveries, use Equation NN–5a of this section and the default value for the CO_2 emission factors found in Table NN–2 of this subpart. Alternatively, a reporter-specific CO_2 emission factor may be used, provided it is developed using methods outlined in § 98.404.

$$CO_{2l} = \left[Fuel_1 - Fuel_2\right] * EF \qquad \text{(Eq. NN-5a)}$$

Where:

CO_{2l} = Annual CO_2 mass emissions that would result from the combustion or oxidation of the net change in natural gas stored on system by the LDC within the reporting year (metric tons).

$Fuel_1$ = Total annual volume of natural gas added to storage on-system or liquefied and stored in the reporting year (Mscf per year).

$Fuel_2$ = Total annual volume of natural gas that is removed from storage or vaporized and removed from storage and used for deliveries to customers or other LDCs by the LDC within the reporting year (Mscf per year).

EF = Annual average CO_2 emission factor for natural gas placed into/removed from storage (MT CO_2/Mscf).

(ii) For natural gas received by the LDC that bypassed the city gate, use Equation NN–5b of this section. This includes natural gas received directly by LDC systems from producers or natural gas processing plants from local production, received as a liquid and vaporized for delivery, or received from any other source that bypassed the city gate. Use the default value for the CO_2 emission factors found in Table NN–2 of this subpart. Alternatively, a reporter-specific CO_2 emission factor may be used, provided it is developed using methods outlined in § 98.404.

$$CO_{2n} = Fuel_z * EF_z \quad \text{(Eq. NN-5b)}$$

Where:

CO_{2n} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas received that bypassed the city gate and is not otherwise accounted for by Equation NN–1 or NN–2 of this section (metric tons).

$Fuel_z$ = Total annual volume of natural gas received that was not otherwise accounted for by Equation NN–1 or NN–2 of this section (natural gas from producers and natural gas processing plants from local production, or natural gas that was received as a liquid, vaporized and delivered, and any other source that bypassed the city gate). (Mscf per year)

EF_z = Fuel-specific CO_2 emission factor (MT CO_2/Mscf)

(4) Calculate the total CO_2 emissions that would result from the complete combustion or oxidation of the annual supply of natural gas to end-users that receive a supply less than 460,000 Mscf per year using Equation NN–6 of this section.

$$CO_2 = CO_{2i} + CO_{2n} - CO_{2j} - \sum CO_{2k} - CO_{2l} \quad \text{(Eq. NN-6)}$$

Where:

CO_2 = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas delivered to LDC end-users not covered in paragraph (b)(2) of this section (metric tons).

CO_{2i} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas received at the city gate as calculated in paragraph (a)(1) or (2) of this section (metric tons).

CO_{2j} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas delivered to transmission pipelines or other LDCs as calculated in paragraph (b)(1) of this section (metric tons).

CO_{2k} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas delivered to each large end-user as calculated in paragraph (b)(2) of this section (metric tons).

CO_{2l} = Annual CO_2 mass emissions that would result from the combustion or oxidation of the net change in natural gas stored by the LDC within the reported year as calculated in paragraph (b)(3)(i) of this section (metric tons).

CO_{2n} = Annual CO_2 mass emissions that would result from the combustion or oxidation of natural gas that was received by the LDC directly from sources bypassing the city gate, and is not otherwise accounted for in Equation NN–1 or NN–2 of this section, as calculated in paragraph (b)(3)(ii) of this section (metric tons).

(c) Each NGL fractionator shall follow the following procedures.

(1)(i) For fractionated NGLs received by the reporter from other NGL fractionators, you shall use Equation NN–7 of this section and the default values for the CO_2 emission factors found in Table NN–2 of this subpart.

(ii) Alternatively, reporter-specific CO_2 emission factors may be used, provided they are developed using methods outlined in § 98.404.

$$CO_{2m} = \sum_g Fuel_g \star EF_g \quad \text{(Eq. NN-7)}$$

Where:

CO_{2m} = Annual CO_2 mass emissions that would result from the combustion or oxidation of each fractionated NGL product "g" received from other fractionators (metric tons).

$Fuel_g$ = Total annual volume of each NGL product "g" received (bbls).

EF_g = Fuel-specific CO_2 emission factor of NGL product "g" (MT CO_2/bbl).

(2) Calculate the total CO_2 equivalent emissions that would result from the combustion or oxidation of fractionated NGLs supplied less the

quantity received from other fractionators using Equation NN–8 of this section.

$$CO_2 = CO_{2i} - CO_{2m} \qquad \text{(Eq. NN-8)}$$

Where:

CO_2 = Annual CO_2 mass emissions that would result from the combustion or oxidation of fractionated NGLs delivered to customers or on behalf of customers less the quantity received from other fractionators (metric tons).

CO_{2i} = Annual CO_2 mass emissions that would result from the combustion or oxidation of fractionated NGLs delivered to all customers or on behalf of customers as calculated in paragraph (a)(1) or (a)(2) of this section (metric tons).

CO_{2m} = Annual CO_2 mass emissions that would result from the combustion or oxidation of fractionated NGLs received from other fractionators and calculated in paragraph (c)(1) of this section (metric tons).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66478, Oct. 28, 2010; 78 FR 71975, Nov. 29, 2013]

§ 98.404 Monitoring and QA/QC requirements.

(a) *Determination of quantity.* (1) NGL fractionators and LDCs shall determine the quantity of NGLs and natural gas using methods in common use in the industry for billing purposes as audited under existing Sarbanes Oxley regulationn.

(i) Where an appropriate standard method published by a consensus-based standards organization exists, such a method shall be used. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, industry standard practices shall be followed.

(2) NGL fractionators and LDCs shall base the minimum frequency of the product quantity measurements, to be summed to the annual quantity reported, on the reporter's standard practices for commercial operations.

(i) For NGL fractionators the minimum frequency of measurements shall be the measurements taken at custody transfers summed to the annual reportable volume.

(ii) For natural gas the minimum frequency of measurement shall be based on the LDC's standard measurement schedules used for billing purposes and summed to the annual reportable volume.

(3) NGL fractionators shall use measurement for NGLs at custody tranfer meters or at such meters that are used to determine the NGL product slate delivered from the fractionation facility.

(4) If a NGL fractionator supplies a product not listed in Table NN–1 of this subpart that is a mixture or blend of two or more products listed in Tables NN–1 and NN–2 of this subpart, the NGL fractionator shall report the quantities of the constituents of the mixtures or blends separately.

(5) For an LDC using Equation NN–1 or NN–2 of this subpart, the point(s) of measurement for the natural gas volume received shall be the LDC city gate meter(s).

(i) If the LDC makes its own quantity measurements according to established business practices, its own measurements shall be used.

(ii) If the LDC does not make its own quantity measurements according to established business practices, it shall use its delivering pipeline invoiced measurements for natural gas deliveries to the LDC city gate, used in determining daily system sendout.

(6) An LDC using Equation NN–3 of this subpart shall measure natural gas at the custody transfer meters.

(7) An LDC using Equation NN–4 of this subpart shall measure natural gas at the large end-user's meter(s). Where a large end-user is known to have more than one meter located at their facility, based on readily available information in the LDCs possession, the reporter shall measure the natural gas at each meter and sum the annual volume delivered to all meters located at the end-user's facility to determine the total volume delivered to the large end-user. Otherwise, the reporter shall

consider the total annual volume delivered through each single meter at a single particular location to be the volume delivered to an individual large end-user.

(8) An LDC using Equation NN–5a and/or NN–5b of this subpart shall measure natural gas as follows:

(i) $Fuel_1$ shall be measured at the on-system storage injection meters and/or at the meters measuring natural gas to be liquefied.

(ii) $Fuel_2$ shall be measured at the meters used for measuring on-system storage withdrawals and/or LNG vaporization injection.

(iii) $Fuel_z$ shall be measured using established business practices.

(9) An LDC shall measure all natural gas under the following standard industry temperature and pressure conditions: Cubic foot of gas at a temperature of 60 degrees Fahrenheit and at an absolute pressure of one atmosphere.

(b) *Determination of higher heating values (HHV).* (1) When a reporter uses the default HHV provided in this section to calculate Equation NN–1 of this subpart, the appropriate value shall be taken from Table NN–1 of this subpart.

(2) When a reporter uses a reporter-specific HHV to calculate Equation NN–1 of this subpart, an appropriate standard test published by a consensus-based standards organization shall be used. Consensus-based standards organizations include, but are not limited to, the following: AGA and GPA.

(i) If an LDC makes its own HHV measurements according to established business practices, then its own measurements shall be used.

(ii) If an LDC does not make its own measurements according to established business practices, it shall use its delivering pipeline measurements.

(c) *Determination of emission factor (EF).* (1) When a reporter used the default EF provided in this section to calculate Equation NN–1 of this subpart, the appropriate value shall be taken from Table NN–1 of this subpart.

(2) When a reporter used the default EF provided in this section to calculate Equation NN–2, NN–3, NN–4, NN–5a, NN–5b, or NN–7 of this subpart, the appropriate value shall be taken from Table NN–2 of this subpart.

(3) When a reporter uses a reporter-specific EF, the reporter shall use an appropriate standard method published by a consensus-based standards organization to conduct compositional analysis necessary to determine reporter-specific CO_2 emission factors. Consensus-based standards organizations include, but are not limited to, the following: AGA and GPA.

(d) *Equipment Calibration.* (1) Equipment used to measure quantities in Equations NN–1, NN–2, NN–5a and NN–5b of this subpart shall be calibrated prior to its first use for reporting under this subpart, using a suitable standard method published by a consensus based standards organization or according to the equipment manufacturer's directions.

(2) Equipment used to measure quantities in Equations NN–1, NN–2, NN–5a, and NN–5b of this subpart shall be recalibrated at the frequency specified by the standard method used or by the manufacturer's directions.

(3) Equipment used to measure quantities in Equations NN–3 and NN–4 of this subpart shall be recalibrated at the frequency commonly used within the industry.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71976, Nov. 29, 2013]

§ 98.405 Procedures for estimating missing data.

(a) Whenever a quality-assured value of the quantity of natural gas liquids or natural gas supplied during any period is unavailable (e.g., if a flow meter malfunctions), a substitute data value for the missing quantity measurement must be used in the calculations according to paragraphs (b) and (c) of this section.

(b) *Determination of quantity.* (1) NGL fractionators shall substitute meter records provided by pipeline(s) for all pipeline receipts of NGLs; by manifests for deliveries made to trucks or rail cars; or metered quantities accepted by the entities purchasing the output from the fractionator whether by pipeline or by truck or rail car. In cases where the metered data from the receiving pipeline(s) or purchasing entities are not available, fractionators may substitute estimates based on contract quantities required to be delivered under purchase or delivery contracts with other parties.

(2) LDCs shall either substitute their delivering pipeline metered deliveries at the city gate or substitute nominations and scheduled delivery quantities for the period when metered values of actual deliveries are not available.

(c) *Determination of HHV and EF.* (1) Whenever an LDC that makes its own HHV measurements according to established business practices cannot follow the quality assurance procedures for developing a reporter-specific HHV, as specified in § 98.404, during any period for any reason, the reporter shall use either its delivering pipeline measurements or the default HHV provided in Table NN–1 of this part for that period.

(2) Whenever an LDC that does not make its own HHV measurements according to established business practices or an NGL fractionator cannot follow the quality assurance procedures for developing a reporter-specific HHV, as specified in § 98.404, during any period for any reason, the reporter shall use the default HHV provided in Table NN–1 of this part for that period.

(3) [Reserved]

(4) Whenever a reporter cannot follow the quality assurance procedures for developing a reporter-specific EF, as specified in § 98.404, during any period for any reason, the reporter shall use the default EF provided in § 98.408 for that period.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71977, Nov. 29, 2013]

§ 98.406 Data reporting requirements.

(a) In addition to the information required by § 98.3(c), the annual report for each NGL fractionator covered by this rule shall contain the following information.

(1) Annual quantity (in barrels) of each NGL product supplied to downstream facilities in the following product categories: ethane, propane, normal butane, isobutane, and pentanes plus.

(2) Annual quantity (in barrels) of each NGL product received from other NGL fractionators in the following product categories: ethane, propane, normal butane, isobutane, and pentanes plus.

(3) Annual volumes in Mscf of natural gas received for processing.

(4) Annual quantities (in barrels) of y-grade, o-grade, and other bulk NGLs:

(i) Received.

(ii) Supplied to downstream users that are not fractionated by the reporter.

(5) Annual quantity (in barrels) of propane that the NGL fractionator odorizes at the facility and delivers to others.

(6) Annual CO_2 emissions (metric tons) that would result from the complete combustion or oxidation of the quantities in paragraphs (a)(1) and (a)(2) of this section, calculated in accordance with § 98.403(a) and (c)(1).

(7) Annual CO_2 mass emissions (metric tons) that would result from the combustion or oxidation of fractionated NGLs supplied less the quantity received from other fractionators, calculated in accordance with § 98.403(c)(2). If the calculated value is negative, the reporter shall report the value as zero.

(8) The specific industry standard used to measure each quantity reported in paragraph (a)(1) of this section.

(9) If the NGL fractionator developed reporter-specific EFs or HHVs, report the following for each product type:

(i) The specific industry standard(s) used to develop reporter-specific higher heating value(s) and/or emission factor(s), pursuant to § 98.404(b)(2) and (c)(3).

(ii) The developed HHV(s).

(iii) The developed EF(s).

(b) In addition to the information required by § 98.3(c), the annual report for each LDC shall contain the following information.

(1) Annual volume in Mscf of natural gas received by the LDC at its city gate stations for redelivery on the LDC's distribution system, including for use by the LDC.

(2) Annual volume in Mscf of natural gas placed into storage or liquefied and stored ($Fuel_1$ in Equation NN–5a).

(3) Annual volume in Mscf of natural gas withdrawn from on-system storage and annual volume in Mscf of vaporized liquefied natural gas (LNG) withdrawn

from storage for delivery on the distribution system ($Fuel_2$ in Equation NN–5a).

(4) [Reserved]

(5) Annual volume in Mscf of natural gas that bypassed the city gate(s) and was supplied through the LDC distribution system. This includes natural gas from producers and natural gas processing plants from local production, or natural gas that was vaporized upon receipt and delivered, and any other source that bypassed the city gate ($Fuel_z$ in Equation NN–5b).

(6) Annual volume in Mscf of natural gas delivered to downstream gas transmission pipelines and other local distribution companies.

(7) Annual volume in Mscf of natural gas delivered by the LDC to each large end-user as defined in §98.403(b)(2)(i) of this section.

(8) The total annual CO_2 mass emissions (metric tons) associated with the volumes in paragraphs (b)(1) through (b)(7) of this section, calculated in accordance with §98.403(a) and (b)(1) through (b)(3).

(9) Annual CO_2 emissions (metric tons) that would result from the complete combustion or oxidation of the annual supply of natural gas to end-users registering less than 460,000 Mscf, calculated in accordance with §98.403(b)(4). If the calculated value is negative, the reporter shall report the value as zero.

(10) The specific industry standard used to develop the volume reported in paragraph (b)(1) of this section.

(11) If the LDC developed reporter-specific EFs or HHVs, report the following:

(i) The specific industry standard(s) used to develop reporter-specific higher heating value(s) and/or emission factor(s), pursuant to §98.404 (b)(2) and (c)(3).

(ii) The developed HHV(s).

(iii) The developed EF(s).

(12) The customer name, address, and meter number of each large end-user reported in paragraph (b)(7) of this section. Additionally, report whether the quantity of natural gas reported in paragraph (b)(7) of this section is the total quantity delivered to a large end-user's facility, or the quantity delivered to a specific meter located at the facility.

(i) If known, report the EIA identification number of each LDC customer.

(ii) [Reserved]

(13) The annual volume in Mscf of natural gas delivered by the local distribution company to each of the following end-use categories. For definitions of these categories, refer to EIA Form 176 (Annual Report of Natural Gas and Supplemental Gas Supply & Disposition) and Instructions.

(i) Residential consumers.

(ii) Commercial consumers.

(iii) Industrial consumers.

(iv) Electricity generating facilities.

(c) Each reporter shall report the number of days in the reporting year for which substitute data procedures were used for the following purpose:

(1) To measure quantity.

(2) To develop HHV(s).

(3) To develop EF(s).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66479, Oct. 28, 2010; 78 FR 71977, Nov. 29, 2013]

§98.407 Records that must be retained.

In addition to the information required by §98.3(g), the reporter shall retain the following records:

(a) Records of all meter readings and documentation to support volumes of natural gas and NGLs that are reported under this part.

(b) Records documenting any estimates of missing metered data and showing the calculations of the values used for the missing data.

(c) Calculations and worksheets used to estimate CO_2 emissions for the volumes reported under this part.

(d) Records related to the large end-users identified in §98.406(b)(7).

(e) Records relating to measured Btu content or carbon content showing specific industry standards used to develop reporter-specific higher heating values and emission factors.

(f) Records of such audits as required by Sarbanes Oxley regulations on the accuracy of measurements of volumes of natural gas and NGLs delivered to customers or on behalf of customers.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 66479, Oct. 28, 2010]

§ 98.408 Definitions.

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

TABLE NN–1 TO SUBPART NN OF PART 98—DEFAULT FACTORS FOR CALCULATION METHODOLOGY 1 OF THIS SUBPART

Fuel	Default higher heating value [1]	Default CO_2 emission factor (kg CO_2/MMBtu)
Natural Gas	1.026 MMBtu/Mscf	53.06
Propane	3.84 MMBtu/bbl	62.87
Normal butane	4.34 MMBtu/bbl	64.77
Ethane	2.85 MMBtu/bbl	59.60
Isobutane	4.16 MMBtu/bbl	64.94
Pentanes plus	4.62 MMBtu/bbl	70.02

[1] Conditions for higher heating values presented in MMBtu/bbl are 60 °F and saturation pressure.

[78 FR 71977, Nov. 29, 2013]

TABLE NN–2 TO SUBPART NN OF PART 98—DEFAULT VALUES FOR CALCULATION METHODOLOGY 2 OF THIS SUBPART

Fuel	Unit	Default CO_2 emission value (MT CO_2/Unit) [1]
Natural Gas	Mscf	0.0544
Propane	Barrel	0.241
Normal butane	Barrel	0.281
Ethane	Barrel	0.170
Isobutane	Barrel	0.270
Pentanes plus	Barrel	0.324

[1] Conditions for emission value presented in MT CO_2/bbl are 60 °F and saturation pressure.

[78 FR 71977, Nov. 29, 2013, as amended at 79 FR 3508, Jan. 22, 2014]

Subpart OO—Suppliers of Industrial Greenhouse Gases

§ 98.410 Definition of the source category.

(a) The industrial gas supplier source category consists of any facility that produces a fluorinated GHG or nitrous oxide, any bulk importer of fluorinated GHGs or nitrous oxide, and any bulk exporter of fluorinated GHGs or nitrous oxide.

(b) To produce a fluorinated GHG means to manufacture a fluorinated GHG from any raw material or feedstock chemical. Producing a fluorinated GHG includes the manufacture of a fluorinated GHG as an isolated intermediate for use in a process that will result in its transformation either at or outside of the production facility. Producing a fluorinated GHG also includes the creation of a fluorinated GHG (with the exception of HFC–23) that is captured and shipped off site for any reason, including destruction. Producing a fluorinated GHG does not include the reuse or recycling of a fluorinated GHG, the creation of HFC–23 during the production of HCFC–22, the creation of intermediates that are created and transformed in a single process with no storage of the intermediates, or the creation of fluorinated GHGs that are released or destroyed at the production facility before the production measurement at § 98.414(a).

(c) To produce nitrous oxide means to produce nitrous oxide by thermally decomposing ammonium nitrate (NH_4NO_3). Producing nitrous oxide does not include the reuse or recycling of nitrous oxide or the creation of by-products that are released or destroyed at the production facility.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79167, Dec. 17, 2010]

§ 98.411 Reporting threshold.

Any supplier of industrial greenhouse gases who meets the requirements of § 98.2(a)(4) must report GHG emissions.

§ 98.412 GHGs to report.

You must report the GHG emissions that would result from the release of the nitrous oxide and each fluorinated GHG that you produce, import, export, transform, or destroy during the calendar year.

§ 98.413 Calculating GHG emissions.

(a) Calculate the total mass of each fluorinated GHG or nitrous oxide produced annually, except for amounts that are captured solely to be shipped off site for destruction, by using Equation OO–1 of this section:

$$P = \sum_{p=1}^{n} P_p \qquad \text{(Eq. OO-1)}$$

P = Mass of fluorinated GHG or nitrous oxide produced annually.

P_p = Mass of fluorinated GHG or nitrous oxide produced over the period ''p''.

(b) Calculate the total mass of each fluorinated GHG or nitrous oxide produced over the period ''p'' by using Equation OO–2 of this section:

$$P_p = O_p - U_p \qquad \text{(Eq. OO-2)}$$

Where:

P_p = Mass of fluorinated GHG or nitrous oxide produced over the period ''p'' (metric tons).

O_p = Mass of fluorinated GHG or nitrous oxide that is measured coming out of the production process over the period p (metric tons).

U_p = Mass of used fluorinated GHG or nitrous oxide that is added to the production process upstream of the output measurement over the period ''p'' (metric tons).

(c) Calculate the total mass of each fluorinated GHG or nitrous oxide transformed by using Equation OO–3 of this section:

$$T = F_T * E_T \qquad \text{(Eq. OO-3)}$$

Where:

T = Mass of fluorinated GHG or nitrous oxide transformed annually (metric tons).

F_T = Mass of fluorinated GHG fed into the transformation process annually (metric tons).

E_T = The fraction of the fluorinated GHG or nitrous oxide fed into the transformation process that is transformed in the process (metric tons).

(d) Calculate the total mass of each fluorinated GHG destroyed by using Equation OO–4 of this section:

$$D = F_D * DE \qquad \text{(Eq. OO-4)}$$

Where:

D = Mass of fluorinated GHG destroyed annually (metric tons).

F_D = Mass of fluorinated GHG fed into the destruction device annually (metric tons).

DE = Destruction efficiency of the destruction device (fraction).

§ 98.414 Monitoring and QA/QC requirements.

(a) The mass of fluorinated GHGs or nitrous oxide coming out of the production process shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the measured mass includes more than one fluorinated GHG, the concentrations of each of the fluorinated GHGs, other than low-concentration constituents, shall be measured as set forth in paragraph (n) of this section. For each fluorinated GHG, the mean of the concentrations of that fluorinated GHG (mass fraction) measured under paragraph (n) of this section shall be multiplied by the mass measurement to obtain the mass of that fluorinated GHG coming out of the production process.

(b) The mass of any used fluorinated GHGs or used nitrous oxide added back into the production process upstream of the output measurement in paragraph (a) of this section shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the mass in paragraph (a) of this section is measured by weighing containers that include returned heels as well as newly produced fluorinated GHGs, the returned heels shall be considered used fluorinated GHGs for purposes of this paragraph (b) of this section and § 98.413(b).

(c) The mass of fluorinated GHGs or nitrous oxide fed into the transformation process shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better.

(d) The fraction of the fluorinated GHGs or nitrous oxide fed into the transformation process that is actually transformed shall be estimated considering yield calculations or quantities of unreacted fluorinated GHGs or nitrous oxide permanently removed from the process and recovered, destroyed, or emitted.

(e) The mass of fluorinated GHG or nitrous oxide sent to another facility for transformation shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better.

(f) The mass of fluorinated GHG sent to another facility for destruction shall be measured using flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the fluorinated GHG, the concentration of the fluorinated GHG shall be estimated considering current or previous representative concentration measurements and other relevant process information. This concentration (mass fraction) shall be multiplied by the mass measurement to obtain the mass of the fluorinated GHG sent to another facility for destruction.

(g) You must estimate the share of the mass of fluorinated GHGs in paragraph (f) of this section that is comprised of fluorinated GHGs that are not included in the mass produced in § 98.413(a) because they are removed from the production process as byproducts or other wastes.

(h) You must measure the mass of each fluorinated GHG that is fed into the destruction device and that was previously produced as defined at § 98.410(b). Such fluorinated GHGs include but are not limited to quantities that are shipped to the facility by another facility for destruction and quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed. You must use flowmeters, weigh scales, or a combination of volumetric and density measurements with an accuracy and precision of one percent of full scale or better. If the measured mass includes more than trace concentrations of materials other than the fluorinated GHG being destroyed, you must estimate the concentrations of the fluorinated GHG being destroyed considering current or previous representative concentration measurements and other relevant process information. You must multiply this concentration (mass fraction) by the mass measurement to obtain the mass of the fluorinated GHG fed into the destruction device.

(i) Very small quantities of fluorinated GHGs that are difficult to measure because they are entrained in other media such as destroyed filters and destroyed sample containers are exempt from paragraphs (f) and (h) of this section.

(j) [Reserved]

(k) For purposes of Equation OO–4 of this subpart, the destruction efficiency can be equated to the destruction efficiency determined during a previous performance test of the destruction device or, if no performance test has been done, the destruction efficiency provided by the manufacturer of the destruction device.

(l) In their estimates of the mass of fluorinated GHGs destroyed, fluorinated GHG production facilities that destroy fluorinated GHGs shall account for any temporary reductions in the destruction efficiency that result from any startups, shutdowns, or malfunctions of the destruction device, including departures from the operating conditions defined in state or local permitting requirements and/or oxidizer manufacturer specifications.

(m) Calibrate all flow meters, weigh scales, and combinations of volumetric and density measures that are used to measure or calculate quantities that are to be reported under this subpart prior to the first year for which GHG emissions are reported under this part. Calibrations performed prior to the effective date of this rule satisfy this requirement. Recalibrate all flow meters, weigh scales, and combinations of volumetric and density measures at the minimum frequency specified by the manufacturer. Use NIST-traceable standards and suitable methods published by a consensus standards organization (e.g., ASTM, ASME, ISO, or others).

(n) If the mass coming out of the production process includes more than one fluorinated GHG, you shall measure the concentrations of all of the fluorinated GHGs, other than low-concentration constituents, as follows:

(1) *Analytical Methods.* Use a quality-assured analytical measurement technology capable of detecting the analyte of interest at the concentration of interest and use a procedure validated with the analyte of interest at the concentration of interest. Where standards for the analyte are not available, a chemically similar surrogate may be used. Acceptable analytical measurement technologies include but are not limited to gas chromatography (GC) with an appropriate detector, infrared (IR), fourier transform infrared (FTIR), and nuclear magnetic resonance (NMR). Acceptable methods include EPA Method 18 in appendix A–1 of 40 CFR part 60; EPA Method 320 in appendix A of 40 CFR part 63; the Protocol for Measuring Destruction or Removal Efficiency (DRE) of Fluorinated Greenhouse Gas Abatement Equipment in Electronics Manufacturing, Version 1, EPA–430–R–10–003, (March 2010) (incorporated by reference, see § 98.7); ASTM D6348–03 Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy (incorporated by reference, see § 98.7); or other analytical methods validated using EPA Method 301 in appendix A of 40 CFR part 63 or some other scientifically sound validation protocol. The validation protocol may include analytical technology manufacturer specifications or recommendations.

(2) *Documentation in GHG Monitoring Plan.* Describe the analytical method(s) used under paragraph (n)(1) of this section in the site GHG Monitoring Plan as required under § 98.3(g)(5). At a minimum, include in the description of the method a description of the analytical measurement equipment and procedures, quantitative estimates of the method's accuracy and precision for the analytes of interest at the concentrations of interest, as well as a description of how these accuracies and precisions were estimated, including the validation protocol used.

(3) *Frequency of measurement.* Perform the measurements at least once by February 15, 2011 if the fluorinated GHG product is being produced on December 17, 2010. Perform the measurements within 60 days of commencing production of any fluorinated GHG product that was not being produced on December 17, 2010. Repeat the measurements if an operational or process change occurs that could change the identities or significantly change the concentrations of the fluorinated GHG constituents of the fluorinated GHG product. Complete the repeat measurements within 60 days of the operational or process change.

(4) *Measure all product grades.* Where a fluorinated GHG is produced at more than one purity level (*e.g.*, pharmaceutical grade and refrigerant grade), perform the measurements for each purity level.

(5) *Number of samples.* Analyze a minimum of three samples of the fluorinated GHG product that have been drawn under conditions that are representative of the process producing the fluorinated GHG product. If the relative standard deviation of the measured concentrations of any of the fluorinated GHG constituents (other than low-concentration constituents) is greater than or equal to 15 percent, draw and analyze enough additional samples to achieve a total of at least six samples of the fluorinated GHG product.

(o) All analytical equipment used to determine the concentration of fluorinated GHGs, including but not limited to gas chromatographs and associated detectors, IR, FTIR and NMR devices, shall be calibrated at a frequency needed to support the type of analysis specified in the site GHG Monitoring Plan as required under §§ 98.414(n) and 98.3(g)(5) of this part. Quality assurance samples at the concentrations of concern shall be used for the calibration. Such quality assurance samples shall consist of or be prepared from certified standards of the analytes of concern where available; if not available, calibration shall be performed by a method specified in the GHG Monitoring Plan.

(p) Isolated intermediates that are produced and transformed at the same facility are exempt from the monitoring requirements of this section.

(q) Low-concentration constituents are exempt from the monitoring and QA/QC requirements of this section.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79167, Dec. 17, 2010]

§ 98.415 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (e.g., if a meter malfunctions), a substitute data value for the missing parameter shall be used in the calculations, according to paragraph (b) of this section.

(b) For each missing value of the mass produced, fed into the production process (for used material being reclaimed), fed into the transformation process, fed into destruction devices, sent to another facility for transformation, or sent to another facility for destruction, the substitute value of that parameter shall be a secondary mass measurement where such a measurement is available. For example, if the mass produced is usually measured with a flowmeter at the inlet to the day tank and that flowmeter fails to meet an accuracy or precision test, malfunctions, or is rendered inoperable, then the mass produced may be estimated by calculating the change in volume in the day tank and multiplying it by the density of the product. Where a secondary mass measurement is not available, the substitute value of the parameter shall be an estimate based on a related parameter. For example, if a flowmeter measuring the mass fed into a destruction device is rendered inoperable, then the mass fed into the destruction device may be estimated using the production rate and the previously observed relationship between the production rate and the mass flow rate into the destruction device.

§ 98.416 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information:

(a) Each fluorinated GHG or nitrous oxide production facility shall report the following information:

(1) Mass in metric tons of each fluorinated GHG or nitrous oxide produced at that facility by process, except for amounts that are captured solely to be shipped off site for destruction.

(2) Mass in metric tons of each fluorinated GHG or nitrous oxide transformed at that facility, by process.

(3) Mass in metric tons of each fluorinated GHG that is destroyed at that facility and that was previously produced as defined at § 98.410(b). Quantities to be reported under this paragraph (a)(3) of this section include but are not limited to quantities that are shipped to the facility by another facility for destruction and quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed.

(4) [Reserved]

(5) Total mass in metric tons of each fluorinated GHG or nitrous oxide sent to another facility for transformation.

(6) Total mass in metric tons of each fluorinated GHG sent to another facility for destruction, except fluorinated GHGs that are not included in the mass produced in § 98.413(a) because they are removed from the production process as by-products or other wastes. Quantities to be reported under this paragraph (a)(6) could include, for example, fluorinated GHGs that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore sent to another facility for destruction.

(7) Total mass in metric tons of each fluorinated GHG that is sent to another facility for destruction and that is not included in the mass produced in §98.413(a) because it is removed from the production process as a byproduct or other waste.

(8)–(9) [Reserved]

(10) Mass in metric tons of any fluorinated GHG or nitrous oxide fed into the transformation process, by process.

(11) Mass in metric tons of each fluorinated GHG that is fed into the destruction device and that was previously produced as defined at §98.410(b). Quantities to be reported under this paragraph (a)(11) of this section include but are not limited to quantities that are shipped to the facility by another facility for destruction and quantities that are returned to the facility for reclamation but are found to be irretrievably contaminated and are therefore destroyed.

(12) Mass in metric tons of each fluorinated GHG or nitrous oxide that is measured coming out of the production process, by process.

(13) Mass in metric tons of each used fluorinated GHGs or nitrous oxide added back into the production process (e.g., for reclamation), including returned heels in containers that are weighed to measure the mass in §98.414(a), by process.

(14) Names and addresses of facilities to which any nitrous oxide or fluorinated GHGs were sent for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sent to each for transformation.

(15) Names and addresses of facilities to which any fluorinated GHGs were sent for destruction, and the quantities (metric tons) of each fluorinated GHG that were sent to each for destruction.

(16) Where missing data have been estimated pursuant to §98.415, the reason the data were missing, the length of time the data were missing, the method used to estimate the missing data, and the estimates of those data.

(b) By March 31, 2011 or within 60 days of commencing fluorinated GHG destruction, whichever is later, a fluorinated GHG production facility or importer that destroys fluorinated GHGs shall submit a one-time report containing the following information for each destruction process:

(1) Destruction efficiency (DE).

(2) Methods used to determine the destruction efficiency.

(3) Methods used to record the mass of fluorinated GHG destroyed.

(4) Chemical identity of the fluorinated GHG(s) used in the performance test conducted to determine DE.

(5) Name of all applicable federal or state regulations that may apply to the destruction process.

(6) If any process changes affect unit destruction efficiency or the methods used to record mass of fluorinated GHG destroyed, then a revised report must be submitted to reflect the changes. The revised report must be submitted to EPA within 60 days of the change.

(c) Each bulk importer of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes its imports at the corporate level, except for shipments including less than twenty-five kilograms of fluorinated GHGs or nitrous oxide, transshipments, and heels that meet the conditions set forth at §98.417(e). The report shall contain the following information for each import:

(1) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk, including each fluorinated GHG constituent of the fluorinated GHG product that makes up between 0.5 percent and 100 percent of the product by mass.

(2) Total mass in metric tons of nitrous oxide and each fluorinated GHG imported in bulk and sold or transferred to persons other than the importer for use in processes resulting in the transformation or destruction of the chemical.

(3) Date on which the fluorinated GHGs or nitrous oxide were imported.

(4) Port of entry through which the fluorinated GHGs or nitrous oxide passed.

(5) Country from which the imported fluorinated GHGs or nitrous oxide were imported.

(6) Commodity code of the fluorinated GHGs or nitrous oxide shipped.

(7) Importer number for the shipment.

(8) Total mass in metric tons of each fluorinated GHG destroyed by the importer.

(9) If applicable, the names and addresses of the persons and facilities to which the nitrous oxide or fluorinated GHGs were sold or transferred for transformation, and the quantities (metric tons) of nitrous oxide and of each fluorinated GHG that were sold or transferred to each facility for transformation.

(10) If applicable, the names and addresses of the persons and facilities to which the fluorinated GHGs were sold or transferred for destruction, and the quantities (metric tons) of each fluorinated GHG that were sold or transferred to each facility for destruction.

(d) Each bulk exporter of fluorinated GHGs or nitrous oxide shall submit an annual report that summarizes its exports at the corporate level, except for shipments including less than twenty-five kilograms of fluorinated GHGs or nitrous oxide, transshipments, and heels. The report shall contain the following information for each export:

(1) Total mass in metric tons of nitrous oxide and each fluorinated GHG exported in bulk.

(2) Names and addresses of the exporter and the recipient of the exports.

(3) Exporter's Employee Identification Number.

(4) Commodity code of the fluorinated GHGs and nitrous oxide shipped.

(5) Date on which, and the port from which, fluorinated GHGs and nitrous oxide were exported from the United States or its territories.

(6) Country to which the fluorinated GHGs or nitrous oxide were exported.

(e) By March 31, 2011, or within 60 days of commencing fluorinated GHG production, whichever is later, a fluorinated GHG production facility shall submit a one-time report describing the following information:

(1) The method(s) by which the producer in practice measures the mass of fluorinated GHGs produced, including the instrumentation used (Coriolis flowmeter, other flowmeter, weigh scale, etc.) and its accuracy and precision.

(2) The method(s) by which the producer in practice estimates the mass of fluorinated GHGs fed into the transformation process, including the instrumentation used (Coriolis flowmeter, other flowmeter, weigh scale, etc.) and its accuracy and precision.

(3) The method(s) by which the producer in practice estimates the fraction of fluorinated GHGs fed into the transformation process that is actually transformed, and the estimated precision and accuracy of this estimate.

(4) The method(s) by which the producer in practice estimates the masses of fluorinated GHGs fed into the destruction device, including the method(s) used to estimate the concentration of the fluorinated GHGs in the destroyed material, and the estimated precision and accuracy of this estimate.

(5) The estimated percent efficiency of each production process for the fluorinated GHG produced.

(f) By March 31, 2011, all fluorinated GHG production facilities shall submit a one-time report that includes the concentration of each fluorinated GHG constituent in each fluorinated GHG product as measured under § 98.414(n). If the facility commences production of a fluorinated GHG product that was not included in the initial report or performs a repeat measurement under § 98.414(n) that shows that the identities or concentrations of the fluorinated GHG constituents of a fluorinated GHG product have changed, then the new or changed concentrations, as well as the date of the change, must be reflected in a revision to the report. The revised report must be submitted to EPA by the March 31st that immediately follows the measurement under § 98.414(n).

(g) Isolated intermediates that are produced and transformed at the same facility are exempt from the reporting requirements of this section.

(h) Low-concentration constituents are exempt from the reporting requirements of this section.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79168, Dec. 17, 2010; 76 FR 73905, Nov. 29, 2011]

§98.417 Records that must be retained.

(a) In addition to the data required by §98.3(g), the fluorinated GHG production facility shall retain the following records:

(1) Dated records of the data used to estimate the data reported under §98.416.

(2) Records documenting the initial and periodic calibration of the analytical equipment (including but not limited to GC, IR, FTIR, or NMR), weigh scales, flowmeters, and volumetric and density measures used to measure the quantities reported under this subpart, including the manufacturer directions or industry standards used for calibration pursuant to §98.414(m) and (o).

(3) Dated records of the total mass in metric tons of each reactant fed into the F–GHG or nitrous oxide production process, by process.

(4) Dated records of the total mass in metric tons of the reactants, by-products, and other wastes permanently removed from the F–GHG or nitrous oxide production process, by process.

(b) In addition to the data required by paragraph (a) of this section, any fluorinated GHG production facility that destroys fluorinated GHGs shall keep records of test reports and other information documenting the facility's one-time destruction efficiency report in §98.416(b).

(c) In addition to the data required by §98.3(g), the bulk importer shall retain the following records substantiating each of the imports that they report:

(1) A copy of the bill of lading for the import.

(2) The invoice for the import.

(3) The U.S. Customs entry form.

(d) In addition to the data required by §98.3(g), the bulk exporter shall retain the following records substantiating each of the exports that they report:

(1) A copy of the bill of lading for the export and

(2) The invoice for the export.

(e) Every person who imports a container with a heel that is not reported under §98.416(c) shall keep records of the amount brought into the United States that document that the residual amount in each shipment is less than 10 percent of the volume of the container and will:

(1) Remain in the container and be included in a future shipment.

(2) Be recovered and transformed.

(3) Be recovered and destroyed.

(4) Be recovered and included in a future shipment.

(f) Isolated intermediates that are produced and transformed at the same facility are exempt from the recordkeeping requirements of this section.

(g) Low-concentration constituents are exempt from the recordkeeping requirements of this section.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79168, Dec. 17, 2010; 76 FR 73905, Nov. 29, 2011]

§98.418 Definitions.

Except as provided below, all of the terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part. If a conflict exists between a definition provided in this subpart and a definition provided in subpart A, the definition in this subpart shall take precedence for the reporting requirements in this subpart.

Isolated intermediate means a product of a process that is stored before subsequent processing. An isolated intermediate is usually a product of chemical synthesis. Storage of an isolated intermediate marks the end of a process. Storage occurs at any time the intermediate is placed in equipment used solely for storage.

Low-concentration constituent means, for purposes of fluorinated GHG production and export, a fluorinated GHG constituent of a fluorinated GHG product that occurs in the product in concentrations below 0.1 percent by mass. For purposes of fluorinated GHG import, low-concentration constituent means a fluorinated GHG constituent of a fluorinated GHG product that occurs in the product in concentrations below 0.5 percent by mass. Low-concentration constituents do not include fluorinated GHGs that are deliberately combined with the product (*e.g.*, to affect the performance characteristics of the product).

[75 FR 79169, Dec. 17, 2010]

Subpart PP—Suppliers of Carbon Dioxide

§ 98.420 Definition of the source category.

(a) The carbon dioxide (CO_2) supplier source category consists of the following:

(1) Facilities with production process units that capture a CO_2 stream for purposes of supplying CO_2 for commercial applications or that capture and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground. Capture refers to the initial separation and removal of CO_2 from a manufacturing process or any other process.

(2) Facilities with CO_2 production wells that extract or produce a CO_2 stream for purposes of supplying CO_2 for commercial applications or that extract and maintain custody of a CO_2 stream in order to sequester or otherwise inject it underground.

(3) Importers or exporters of bulk CO_2.

(b) This source category is focused on upstream supply. It does not cover:

(1) Storage of CO_2 above ground or in geologic formations.

(2) Use of CO_2 in enhanced oil and gas recovery.

(3) Transportation or distribution of CO_2.

(4) Purification, compression, or processing of CO_2.

(5) On-site use of CO_2 captured on site.

(c) This source category does not include CO_2 imported or exported in equipment, such as fire extinguishers.

§ 98.421 Reporting threshold.

Any supplier of CO_2 who meets the requirements of § 98.2(a)(4) of subpart A of this part must report the mass of CO_2 captured, extracted, imported, or exported.

§ 98.422 GHGs to report.

(a) Mass of CO_2 captured from production process units.

(b) Mass of CO_2 extracted from CO_2 production wells.

(c) Mass of CO_2 imported.

(d) Mass of CO_2 exported.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79169, Dec. 17, 2010]

§ 98.423 Calculating CO_2 supply.

(a) Except as allowed in paragraph (b) of this section, calculate the annual mass of CO_2 captured, extracted, imported, or exported through each flow meter in accordance with the procedures specified in either paragraph (a)(1) or (a)(2) of this section. If multiple flow meters are used, you shall calculate the annual mass of CO_2 for all flow meters according to the procedures specified in paragraph (a)(3) of this section.

(1) For each mass flow meter, you shall calculate quarterly the mass of CO_2 in a CO_2 stream in metric tons by multiplying the mass flow by the composition data, according to Equation PP–1 of this section. Mass flow and composition data measurements shall be made in accordance with § 98.424 of this subpart.

$$\mathrm{CO_{2,u}} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2},p,u} \qquad \text{(Eq. PP-1)}$$

Where:

$CO_{2,u}$ = Annual mass of CO_2 (metric tons) through flow meter u.

$C_{CO_2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. %CO_2).

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons).

p = Quarter of the year.

u = Flow meter.

(2) For each volumetric flow meter, you shall calculate quarterly the mass of CO_2 in a CO_2 stream in metric tons by multiplying the volumetric flow by

the concentration and density data, according to Equation PP–2 of this section. Volumetric flow, concentration and density data measurements shall be made in accordance with § 98.424 of this section.

$$\mathrm{CO}_{2,\mathrm{u}} = \sum_{p=1}^{4} Q_p * D_p * C_{CO_{2,p}} \qquad \text{(Eq. PP-2)}$$

Where:

$CO_{2,u}$ = Annual mass of CO_2 (metric tons) through flow meter u.

$C_{CO2,p}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (measured as either volume % CO_2 or weight % CO_2).

Q_p = Quarterly volumetric flow rate measurement for flow meter u in quarter p (standard cubic meters).

D_p = Density of CO_2 in quarter p (metric tons CO_2 per standard cubic meter) for flow meter u if $C_{CO2,p}$ is measured as volume % CO_2, or density of the whole CO_2 stream for flow meter u (metric tons per standard cubic meter) if $C_{CO2,p}$ is measured as weight % CO_2.

p = Quarter of the year.

u = Flow meter.

(3) To aggregate data, use either Equation PP–3a or PP–3b in this paragraph, as appropriate.

(i) For facilities with production process units or production wells that capture or extract a CO_2 stream and either measure it after segregation or do not segregate the flow, calculate the total CO_2 supplied in accordance with Equation PP–3a in paragraph (a)(3).

$$\mathrm{CO}_2 = \sum_{\mathrm{p}=1}^{\mathrm{U}} \mathrm{CO}_{2,\mathrm{u}} \qquad \text{(Eq. PP-3a)}$$

where:

CO_2 = Total annual mass of CO_2 (metric tons).

$CO_{2,u}$ = Annual mass of CO_2 (metric tons) through flow meter u.

u = Flow meter.

(ii) For facilities with production process units that capture a CO_2 stream and measure it ahead of segregation, calculate the total CO_2 supplied in accordance with Equation PP–3b.

$$\mathrm{CO}_2 = \sum_{\mathrm{p}=1}^{\mathrm{U}} \mathrm{CO}_{2,\mathrm{u}} - \sum_{p=1}^{V} \mathrm{CO}_{2,\mathrm{v}} \qquad \text{(Eq. PP-3b)}$$

where:

CO_2 = Total annual mass of CO_2 (metric tons).

$CO_{2,u}$ = Annual mass of CO_2 (metric tons) through main flow meter u.

$CO_{2,v}$ = Annual mass of CO_2 (metric tons) through subsequent flow meter v for use on site.

u = Main flow meter.

v = Subsequent flow meter.

(b) As an alternative to paragraphs (a)(1) through (3) of this section for CO_2 that is supplied in containers, calculate the annual mass of CO_2 supplied in containers delivered by each CO_2 stream in accordance with the procedures specified in either paragraph (b)(1) or (b)(2) of this section. If multiple CO_2 streams are used to deliver CO_2 to containers, you shall calculate the annual mass of CO_2 supplied in containers delivered by all CO_2 streams according to the procedures specified in paragraph (b)(3) of this section.

(1) For each CO_2 stream that delivers CO_2 to containers, for which mass is measured, you shall calculate CO_2 supply in containers using Equation PP–1 of this section.

where:

$CO_{2,u}$ = Annual mass of CO_2 (metric tons) supplied in containers delivered by CO_2 stream u.
$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement of CO_2 stream u that delivers CO_2 to containers in quarter p (wt. $\%CO_2$).
$Q_{p,u}$ = Quarterly mass of contents supplied in all containers delivered by CO_2 stream u in quarter p (metric tons).
p = Quarter of the year.
u = CO_2 stream that delivers to containers.

(2) For each CO_2 stream that delivers to containers, for which volume is measured, you shall calculate CO_2 supply in containers using Equation PP–2 of this section.

where:

$CO_{2,u}$ = Annual mass of CO_2 (metric tons) supplied in containers delivered by CO_2 stream u.
$C_{CO2,p}$ = Quarterly CO_2 concentration measurement of CO_2 stream u that delivers CO_2 to containers in quarter p (measured as either volume % CO_2 or weight % CO_2).
Q_p = Quarterly volume of contents supplied in all containers delivered by CO_2 stream u in quarter p (standard cubic meters).
D_p = Quarterly CO_2 density determination for CO_2 stream u in quarter p (metric tons per standard cubic meter) if $CO_{2,p}$ is measured as volume % CO_2, or density of CO_2 stream u (metric tons per standard cubic meter) if $CO_{2,p}$ is measured as weight % CO_2.
p = Quarter of the year.
u = CO_2 stream that delivers to containers.

(3) To aggregate data, sum the mass of CO_2 supplied in containers delivered by all CO_2 streams in accordance with Equation PP–3a of this section.

where:

CO_2 = Annual mass of CO_2 (metric tons) supplied in containers delivered by all CO_2 streams.
$CO_{2,u}$ = Annual mass of CO_2 (metric tons) supplied in containers delivered by CO_2 stream u.
u = CO_2 stream that delivers to containers.

(c) Importers or exporters that import or export CO_2 in containers shall calculate the total mass of CO_2 imported or exported in metric tons based on summing the mass in each CO_2 container using weigh bills, scales, or load cells according to Equation PP–4 of this section.

$$CO_2 = \sum_{p=1}^{I} Q \qquad \text{(Eq. PP-4)}$$

where:

CO_2 = Annual mass of CO_2 (metric tons).
Q = Annual mass in all CO_2 containers imported or exported during the reporting year (metric tons).

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79169, Dec. 17, 2010; 78 FR 71977, Nov. 29, 2013]

§ 98.424 Monitoring and QA/QC requirements.

(a) *Determination of quantity*. (1) Reporters following the procedures in § 98.423(a) shall determine quantity using a flow meter or meters located in accordance with this paragraph.

(i) If the CO_2 stream is segregated such that only a portion is captured for commercial application or for injection, you must locate the flow meter according to the following:

(A) For reporters following the procedures in § 98.423(a)(3)(i), you must locate the flow meter(s) after the point of segregation.

(B) For reporters following the procedures in paragraph (a)(3)(ii) of § 98.423, you must locate the main flow meter(s) on the captured CO_2 stream(s) prior to the point of segregation and the subsequent flow meter(s) on the CO_2 stream(s) for on-site use after the point of segregation. You may only follow the procedures in paragraph (a)(3)(ii) of § 98.423 if the CO_2 stream(s) for on-site use is/are the only diversion(s) from the main, captured CO_2 stream(s) after the main flow meter location(s).

(ii) Reporters that have a mass flow meter or volumetric flow meter installed to measure the flow of a CO_2 stream that meets the requirements of paragraph (a)(1)(i) of this section shall base calculations in § 98.423 of this subpart on the installed mass flow or volumetric flow meters.

(iii) Reporters that do not have a mass flow meter or volumetric flow meter installed to measure the flow of the CO_2 stream that meets the requirements of paragraph (a)(1)(i) of this section shall base calculations in § 98.423 of this subpart on the flow of gas transferred off site using a mass flow meter or a volumetric flow meter located at the point of off-site transfer.

(2) Reporters following the procedures in paragraph (b) of § 98.423 shall determine quantity in accordance with this paragraph.

(i) Reporters that supply CO_2 in containers using weigh bills, scales, or load cells shall measure the mass of contents of each CO_2 container to which the CO_2 stream is delivered, sum the mass of contents supplied in all containers to which the CO_2 stream is delivered during each quarter, sample the CO_2 stream delivering CO_2 to containers on a quarterly basis to determine the composition of the CO_2 stream, and apply Equation PP–1.

(ii) Reporters that supply CO_2 in containers using loaded container volumes shall measure the volume of contents of each CO_2 container to which the CO_2 stream is delivered, sum the volume of contents supplied in all containers to which the CO_2 stream is delivered during each quarter, sample the CO_2 stream on a quarterly basis to determine the composition of the CO_2 stream, determine the density quarterly, and apply Equation PP–2.

(3) Importers or exporters that import or export CO_2 in containers shall measure the mass in each CO_2 container using weigh bills, scales, or load cells and sum the mass in all containers imported or exported during the reporting year.

(4) All flow meters, scales, and load cells used to measure quantities that are reported in § 98.423 of this subpart shall be operated and calibrated according to the following procedure:

(i) You shall use an appropriate standard method published by a consensus-based standards organization if such a method exists. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(ii) Where no appropriate standard method developed by a consensus-based standards organization exists, you shall follow industry standard practices.

(iii) You must ensure that any flow meter calibrations performed are NIST traceable.

(5) Reporters using Equation PP–2 of this subpart and measuring CO_2 concentration as weight % CO_2 shall determine the density of the CO_2 stream on a quarterly basis in order to calculate the mass of the CO_2 stream according to one of the following procedures:

(i) You may use 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*). The method(s) used shall be documented in the Monitoring Plan required under § 98.3(g)(5).

(ii) You may follow an industry standard method.

(b) *Determination of concentration.* (1) Reporters using Equation PP–1 or PP–2 of this subpart shall sample the CO_2 stream on a quarterly basis to determine the composition of the CO_2 stream.

(2) Methods to measure the composition of the CO_2 stream must conform to applicable chemical analytical standards. Acceptable methods include, but are not limited to, the U.S. Food and Drug Administration food-grade specifications for CO_2 (*see* 21 CFR 184.1240) and ASTM standard E1747–95 (Reapproved 2005) Standard Guide for Purity of Carbon Dioxide Used in Supercritical Fluid Applications (ASTM International, 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, *http://www.astm.org*).

(c) You shall convert the density of the CO_2 stream(s) and all measured volumes of carbon dioxide to the following standard industry temperature and pressure conditions: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere. If you apply the density value for CO_2 at standard conditions, you must use 0.001868 metric tons per standard cubic meter.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79170, Dec. 17, 2010]

§ 98.425 Procedures for estimating missing data.

(a) Whenever the quality assurance procedures in § 98.424(a)(1) of this subpart cannot be followed to measure quarterly mass flow or volumetric flow of CO_2, the most appropriate of the following missing data procedures shall be followed:

(1) A quarterly CO_2 mass flow or volumetric flow value that is missing may be substituted with a quarterly value measured during another quarter of the current reporting year.

(2) A quarterly CO_2 mass flow or volumetric flow value that is missing may be substituted with a quarterly value measured during the same quarter from the past reporting year.

(3) If a mass or volumetric flow meter is installed to measure the CO_2 stream, you may substitute data from a mass or volumetric flow meter measuring the CO_2 stream transferred for any period during which the installed meter is inoperable.

(4) The mass or volumetric flow used for purposes of product tracking and billing according to the reporter's established procedures may be substituted for any period during which measurement equipment is inoperable.

(b) Whenever the quality assurance procedures in § 98.424(b) of this subpart cannot be followed to determine concentration of the CO_2 stream, the most appropriate of the following missing data procudures shall be followed:

(1) A quarterly concentration value that is missing may be substituted with a quarterly value measured during another quarter of the current reporting year.

(2) A quarterly concentration value that is missing may be substituted with a quarterly value measured during the same quarter from the previous reporting year.

(3) The concentration used for purposes of product tracking and billing according to the reporter's established procedures may be substituted for any quarterly value.

(c) Missing data on density of the CO_2 stream shall be substituted with quarterly or annual average values from the previous calendar year.

(d) Whenever the quality assurance procedures in § 98.424(a)(2) of this subpart cannot be followed to measure quarterly quantity of CO_2 in containers, the most appropriate of the following missing data procedures shall be followed:

(1) A quarterly quantity of CO_2 in containers that is missing may be substituted with a quarterly value measured during another representative quarter of the current reporting year.

(2) A quarterly quantity of CO_2 in containers that is missing may be substituted with a quarterly value measured during the same quarter from the past reporting year.

(3) The quarterly quantity of CO_2 in containers recorded for purposes of product tracking and billing according to the reporter's established procedures

may be substituted for any period during which measurement equipment is inoperable.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79171, Dec. 17, 2010]

§ 98.426 Data reporting requirements.

In addition to the information required by § 98.3(c) of subpart A of this part, the annual report shall contain the following information, as applicable:

(a) If you use Equation PP–1 of this subpart, report the following information for each mass flow meter or CO_2 stream that delivers CO_2 to containers:

(1) Annual mass in metric tons of CO_2.

(2) Quarterly mass in metric tons of CO_2.

(3) Quarterly concentration of the CO_2 stream.

(4) The standard used to measure CO_2 concentration.

(5) The location of the flow meter in your process chain in relation to the points of CO_2 stream capture, dehydration, compression, and other processing.

(b) If you use Equation PP–2 of this subpart, report the following information for each volumetric flow meter or CO_2 stream that delivers CO_2 to containers:

(1) Annual mass in metric tons of CO_2.

(2) Quarterly volume in standard cubic meters of CO_2.

(3) Quarterly concentration of the CO_2 stream in volume or weight percent.

(4) Report density as follows:

(i) Quarterly density of the CO_2 stream in metric tons per standard cubic meter if you report the concentration of the CO_2 stream in paragraph (b)(3) of this section in weight percent.

(ii) Quarterly density of CO_2 in metric tons per standard cubic meter if you report the concentration of the CO_2 stream in paragraph (b)(3) of this section in volume percent.

(5) The method used to measure density.

(6) The standard used to measure CO_2 concentration.

(7) The location of the flow meter in your process chain in relation to the points of CO_2 stream capture, dehydration, compression, and other processing.

(c) For the aggregated annual mass of CO_2 emissions calculated using Equation PP–3a or PP–3b, report the following:

(1) If you use Equation PP–3a of this subpart, report the annual CO_2 mass in metric tons from all flow meters and CO_2 streams that deliver CO_2 to containers.

(2) If you use Equation PP–3b of this subpart, report:

(i) The total annual CO_2 mass through main flow meter(s) in metric tons.

(ii) The total annual CO_2 mass through subsequent flow meter(s) in metric tons.

(iii) The total annual CO_2 mass supplied in metric tons.

(iv) The location of each flow meter in relation to the point of segregation.

(d) If you use Equation PP–4 of this subpart, report at the corporate level the annual mass of CO_2 in metric tons in all CO_2 containers that are imported or exported.

(e) Each reporter shall report the following information:

(1) The type of equipment used to measure the total flow of the CO_2 stream or the total mass or volume in CO_2 containers.

(2) The standard used to operate and calibrate the equipment reported in (e)(1) of this section.

(3) The number of days in the reporting year for which substitute data procedures were used for the following purpose:

(i) To measure quantity.

(ii) To measure concentration.

(iii) To measure density.

(f) Report the aggregated annual quantity of CO_2 in metric tons that is transferred to each of the following end use applications, if known:

(1) Food and beverage.

(2) Industrial and municipal water/wastewater treatment.

(3) Metal fabrication, including welding and cutting.

(4) Greenhouse uses for plant growth.

(5) Fumigants (e.g., grain storage) and herbicides.

(6) Pulp and paper.

(7) Cleaning and solvent use.

(8) Fire fighting.

(9) Transportation and storage of explosives.

(10) Injection of carbon dioxide for enhanced oil and natural gas recovery that is covered by subpart UU of this part.

(11) Geologic sequestration of carbon dioxide that is covered by subpart RR of this part.

(12) Research and development.

(13) Other.

(g) Each production process unit that captures a CO_2 stream for purposes of supplying CO_2 for commercial applications or in order to sequester or otherwise inject it underground when custody of the CO_2 is maintained shall report the percentage of that stream, if any, that is biomass-based during the reporting year.

[74 FR 56374, Oct. 30, 2009, as amended at 75 FR 79171, Dec. 17, 2010; 78 FR 71977, Nov. 29, 2013]

§ 98.427 Records that must be retained.

In addition to the records required by § 98.3(g) of subpart A of this part, you must retain the records specified in paragraphs (a) through (c) of this section, as applicable.

(a) The owner or operator of a facility containing production process units must retain quarterly records of captured or transferred CO_2 streams and composition.

(b) The owner or operator of a CO_2 production well facility must maintain quarterly records of the mass flow or volumetric flow of the extracted or transferred CO_2 stream and concentration and density if volumetric flow meters are used.

(c) Importers or exporters of CO_2 must retain annual records of the mass flow, volumetric flow, and mass of CO_2 imported or exported.

§ 98.428 Definitions.

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

Subpart QQ—Importers and Exporters of Fluorinated Greenhouse Gases Contained in Pre-Charged Equipment or Closed-Cell Foams

SOURCE: 75 FR 74856, Dec. 1, 2010, unless otherwise noted.

§ 98.430 Definition of the source category.

(a) The source category, importers and exporters of fluorinated GHGs contained in pre-charged equipment or closed-cell foams, consists of any entity that imports or exports pre-charged equipment that contains a fluorinated GHG, and any entity that imports or exports closed-cell foams that contain a fluorinated GHG.

§ 98.431 Reporting threshold.

Any importer or exporter of fluorinated GHGs contained in pre-charged equipment or closed-cell foams who meets the requirements of § 98.2(a)(4) must report each fluorinated GHG contained in the imported or exported pre-charged equipment or closed-cell foams.

§ 98.432 GHGs to report.

You must report the mass of each fluorinated GHG contained in pre-charged equipment or closed-cell foams that you import or export during the calendar year. For imports and exports of closed-cell foams where you do not know the identity and mass of the fluorinated GHG, you must report the mass of fluorinated GHG in CO_2e.

§ 98.433 Calculating GHG contained in pre-charged equipment or closed-cell foams.

(a) The total mass of each fluorinated GHG imported and exported inside equipment or foams must be estimated using Equation QQ–1 of this section:

$$I = \sum_t S_t * N_t * 0.001 \quad \text{(Eq. QQ-1)}$$

where:

I = Total mass of the fluorinated GHG imported or exported annually (metric tons).

t = Equipment/foam type containing the fluorinated GHG.

S_t = Mass of fluorinated GHG per unit of equipment type t or foam type t (charge per piece of equipment, kg) or density of fluorinated GHG in foam (charge per cubic foot of foam, kg per cubic foot).

N_t = Number of units of equipment type t or foam type t imported or exported annually (pieces of equipment or cubic feet of foam).

0.001 = Factor converting kg to metric tons.

(b) When the identity and mass of fluorinated GHGs in a closed-cell foam is unknown to the importer or exporter, the total mass in CO_2e for the fluorinated GHGs imported and exported inside closed-cell foams must be estimated using Equation QQ–2 of this section:

$$I = \sum_t S_t * N_t * 0.001 \quad \text{(Eq. QQ-2)}$$

where:

I = Total mass in CO_2e of the fluorinated GHGs imported or exported in close-cell foams annually (metric tons).

t = Equipment/foam type containing the fluorinated GHG.

S_t = Mass in CO_2e of the fluorinated GHGs per unit of equipment type t or foam type t (charge per piece of equipment, kg) or density of fluorinated GHG in foam (CO_2e per cubic foot of foam, kg CO_2e per cubic foot).

N_t = Number of units of equipment type t or foam type t imported or exported annually (pieces of equipment or cubic feet of foam).

0.001 = Factor converting kg to metric tons.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71978, Nov. 29, 2013]

§ 98.434 Monitoring and QA/QC requirements.

(a) For calendar year 2011 monitoring, you may follow the provisions of § 98.3(d)(1) through (d)(2) for best available monitoring methods rather than follow the monitoring requirements of this section. For purposes of this subpart, any reference in § 98.3(d)(1) through (d)(2) to the year 2010 means 2011, to March 31 means June 30, and to April 1 means July 1. Any reference to the effective date or date of promulgation in § 98.3(d)(1) through (d)(2) means February 28, 2011.

(b) The inputs to the annual submission must be reviewed against the import or export transaction records to ensure that the information submitted to EPA is being accurately transcribed as the correct chemical or blend in the correct pre-charged equipment or closed-cell foam in the correct quantities and units.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71978, Nov. 29, 2013]

§ 98.435 Procedures for estimating missing data.

Procedures for estimating missing data are not provided for importers and exporters of fluorinated GHGs contained in pre-charged equipment or closed-cell foams. A complete record of all measured parameters used in tracking fluorinated GHGs contained in pre-charged equipment or closed-cell foams is required.

§ 98.436 Data reporting requirements.

(a) Each importer of fluorinated GHGs contained in pre-charged equipment or closed-cell foams must submit an annual report that summarizes its imports at the corporate level, except for transshipments, as specified:

(1) Total mass in metric tons of each fluorinated GHG imported in pre-charged equipment or closed-cell foams.

(2) For each type of pre-charged equipment with a unique combination of charge size and charge type, the identity of the fluorinated GHG used as a refrigerant or electrical insulator, charge size (holding charge, if applicable), and number imported.

(3) For closed-cell foams that are imported inside of equipment, the identity of the fluorinated GHG contained in the foam, the mass of the fluorinated GHG contained in the foam

in each piece of equipment, and the number of pieces of equipment imported with each unique combination of mass and identity of fluorinated GHG within the closed-cell foams.

(4) For closed cell-foams that are not imported inside of equipment, the identity of the fluorinated GHG in the foam, the density of the fluorinated GHG in the foam (kg fluorinated GHG/cubic foot), and the volume of foam imported (cubic feet) for each type of closed-cell foam with a unique combination of fluorinated GHG density and identity.

(5) Dates on which the pre-charged equipment or closed-cell foams were imported.

(6) If the importer does not know the identity and mass of the fluorinated GHGs within the closed-cell foam, the importer must report the following:

(i) Total mass in metric tons of CO_2e of the fluorinated GHGs imported in closed-cell foams.

(ii) For closed-cell foams that are imported inside of equipment, the mass of the fluorinated GHGs in CO_2e contained in the foam in each piece of equipment and the number of pieces of equipment imported for each equipment type.

(iii) For closed-cell foams that are not imported inside of equipment, the density in CO_2e of the fluorinated GHGs in the foam (kg CO_2e/cubic foot) and the volume of foam imported (cubic feet) for each type of closed-cell foam.

(iv) Dates on which the closed-cell foams were imported.

(v) Name of the foam manufacturer for each type of closed-cell foam where the identity and mass of the fluorinated GHGs is unknown.

(vi) Certification that the importer was unable to obtain information on the identity and mass of the fluorinated GHGs within the closed-cell foam from the closed-cell foam manufacturer or manufacturers.

(b) Each exporter of fluorinated GHGs contained in pre-charged equipment or closed-cell foams must submit an annual report that summarizes its exports at the corporate level, except for transshipments, as specified:

(1) Total mass in metric tons of each fluorinated GHG exported in pre-charged equipment or closed-cell foams.

(2) For each type of pre-charged equipment with a unique combination of charge size and charge type, the identity of the fluorinated GHG used as a refrigerant or electrical insulator, charge size (including holding charge, if applicable), and number exported.

(3) For closed-cell foams that are exported inside of equipment, the identity of the fluorinated GHG contained in the foam in each piece of equipment, the mass of the fluorinated GHG contained in the foam in each piece of equipment, and the number of pieces of equipment exported with each unique combination of mass and identity of fluorinated GHG within the closed-cell foams.

(4) For closed-cell foams that are not exported inside of equipment, the identity of the fluorinated GHG in the foam, the density of the fluorinated GHG in the foam (kg fluorinated GHG/cubic foot), and the volume of foam exported (cubic feet) for each type of closed-cell foam with a unique combination of fluorinated GHG density and identity.

(5) Dates on which the pre-charged equipment or closed-cell foams were exported.

(6) If the exporter does not know the identity and mass of the fluorinated GHG within the closed-cell foam, the exporter must report the following:

(i) Total mass in metric tons of CO_2e of the fluorinated GHGs exported in closed-cell foams.

(ii) For closed-cell foams that are exported inside of equipment, the mass of the fluorinated GHGs in CO_2e contained in the foam in each piece of equipment and the number of pieces of equipment imported for each equipment type.

(iii) For closed-cell foams that are not exported inside of equipment, the density in CO_2e of the fluorinated GHGs in the foam (kg CO_2 e/cubic foot) and the volume of foam imported (cubic feet) for each type of closed-cell foam.

(iv) Dates on which the closed-cell foams were exported.

(v) Name of the foam manufacturer for each type of closed-cell foam where the identity and mass of the fluorinated GHGg is unknown.

(vi) Certification that the exporter was unable to obtain information on the identity and mass of the fluorinated GHGs within the closed-cell foam from the closed-cell foam manufacturer or manufacturers.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71978, Nov. 29, 2013]

§ 98.437 Records that must be retained.

(a) In addition to the data required by § 98.3(g), importers of fluorinated GHGs in pre-charged equipment and closed-cell foams must retain the following records substantiating each of the imports that they report:

(1) A copy of the bill of lading for the import.

(2) The invoice for the import.

(3) The U.S. Customs entry form.

(4) Ports of entry through which the pre-charged equipment or closed-cell foams passed.

(5) Countries from which the pre-charged equipment or closed-cell foams were imported.

(6) For importers that report the mass of fluorinated GHGs within closed-cell foams on a CO_2e basis, correspondence or other documents that show the importer was unable to obtain information on the identity and mass of fluorinated GHG within closed-cell foams from the foam manufacturer.

(b) In addition to the data required by § 98.3(g), exporters of fluorinated GHGs in pre-charged equipment and closed-cell foams must retain the following records substantiating each of the exports that they report:

(1) A copy of the bill of lading for the export and

(2) The invoice for the export.

(3) Ports of exit through which the pre-charged equipment or closed-cell foams passed.

(4) Countries to which the pre-charged equipment or closed-cell foams were exported.

(5) For exporters that report the mass of fluorinated GHGs within closed-cell foams on a CO_2e basis, correspondence or other documents that show the exporter was unable to obtain information on the identity and mass of fluorinated GHG within closed-cell foams from the foam manufacturer.

(c) For importers and exports of fluorinated GHGs inside pre-charged equipment and closed-cell foams, the GHG Monitoring Plans, as described in § 98.3(g)(5), must be completed by April 1, 2011.

(d) Persons who transship pre-charged equipment and closed-cell foams containing fluorinated GHGs must maintain records that indicated that the pre-charged equipment or foam originated in a foreign country and was destined for another foreign country and did not enter into commerce in the United States.

§ 98.438 Definitions.

Except as provided in this section, all of the terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part. If a conflict exists between a definition provided in this subpart and a definition provided in subpart A, the definition in this subpart must take precedence for the reporting requirements in this subpart.

Appliance means any device which contains and uses a fluorinated greenhouse gas refrigerant and which is used for household or commercial purposes, including any air conditioner, refrigerator, chiller, or freezer.

Closed-cell foam means any foam product, excluding packaging foam, that is constructed with a closed-cell structure and a blowing agent containing a fluorinated GHG. Closed-cell foams include but are not limited to polyurethane (PU) foam contained in equipment, PU continuous and discontinuous panel foam, PU one component foam, PU spray foam, extruded polystyrene (XPS) boardstock foam, and XPS sheet foam. Packaging foam means foam used exclusively during shipment or storage to temporarily enclose items.

Electrical equipment means gas-insulated substations, circuit breakers, other switchgear, gas-insulated lines, or power transformers.

Fluorinated GHG refrigerant means, for purposes of this subpart, any substance consisting in part or whole of a fluorinated greenhouse gas and that is used for heat transfer purposes and provides a cooling effect.

Pre-charged appliance means any appliance charged with fluorinated greenhouse gas refrigerant prior to sale or distribution or offer for sale or distribution in interstate commerce. This includes both appliances that contain the full charge necessary for operation and appliances that contain a partial "holding" charge of the fluorinated greenhouse gas refrigerant (e.g., for shipment purposes).

Pre-charged appliance component means any portion of an appliance, including but not limited to condensers, compressors, line sets, and coils, that is charged with fluorinated greenhouse gas refrigerant prior to sale or distribution or offer for sale or distribution in interstate commerce.

Pre-charged electrical equipment means any electrical equipment, including but not limited to gas-insulated substations, circuit breakers, other switchgear, gas-insulated lines, or power transformers containing a fluorinated GHG prior to sale or distribution, or offer for sale or distribution in interstate commerce. This includes both equipment that contain the full charge necessary for operation and equipment that contain a partial "holding" charge of the fluorinated GHG (e.g., for shipment purposes).

Pre-charged electrical equipment component means any portion of electrical equipment that is charged with a fluorinated greenhouse gas prior to sale or distribution or offer for sale or distribution in interstate commerce.

Pre-charged equipment means any pre-charged appliance, pre-charged appliance component, pre-charged electrical equipment, or pre-charged electrical equipment component.

[74 FR 56374, Oct. 30, 2009, as amended at 78 FR 71978, Nov. 29, 2013]

Subpart RR—Geologic Sequestration of Carbon Dioxide

SOURCE: 75 FR 75078, Dec. 1, 2010, unless otherwise noted.

§ 98.440 Definition of the source category.

(a) The geologic sequestration of carbon dioxide (CO_2) source category comprises any well or group of wells that inject a CO_2 stream for long-term containment in subsurface geologic formations.

(b) This source category includes all wells permitted as Class VI under the Underground Injection Control program.

(c) This source category does not include a well or group of wells where a CO_2 stream is being injected in subsurface geologic formations to enhance the recovery of oil or natural gas unless one of the following applies:

(1) The owner or operator injects the CO_2 stream for long-term containment in subsurface geologic formations and has chosen to submit a proposed monitoring, reporting, and verification (MRV) plan to EPA and received an approved plan from EPA.

(2) The well is permitted as Class VI under the Underground Injection Control program.

(d) *Exemption for research and development projects.* Research and development projects shall receive an exemption from reporting under this subpart for the duration of the research and development activity.

(1) *Process for obtaining an exemption.* If you are a research and development project, you must submit the information in paragraph (d)(2) of this section to EPA by the time you would be otherwise required to submit an MRV plan under § 98.448. EPA will use this information to verify that the project is a research and development project.

(2) *Content of submission.* A submission in support of an exemption as a research and development project must contain the following information:

(i) The planned duration of CO_2 injection for the project.

(ii) The planned annual CO_2 injection volumes during this time period.

(iii) The research purposes of the project.

(iv) The source and type of funding for the project.

(v) The class and duration of Underground Injection Control permit or, for an offshore facility not subject to the Safe Drinking Water Act, a description of the legal instrument authorizing geologic sequestration.

(3) *Determination by the Administrator.*

(i) The Administrator shall determine if a project meets the definition of research and development project within 60 days of receipt of the submission of a request for exemption. In making this determination, the Administrator shall take into account any information you submit demonstrating that the planned duration of CO_2 injection for the project and the planned annual CO_2 injection volumes during the duration of the project are consistent with the purpose of the research and development project.

(ii) Any appeal of the Administrator's determination is subject to the provisions of part 78 of this chapter.

(iii) A project that the Administrator determines is not eligible for an exemption as a research and development project must submit a proposed MRV plan to EPA within 180 days of the Administrator's determination. You may request one extension of up to an additional 180 days in which to submit the proposed MRV plan.

§ 98.441 Reporting threshold.

(a) You must report under this subpart if any well or group of wells within your facility injects any amount of CO_2 for long-term containment in subsurface geologic formations. There is no threshold.

(b) *Request for discontinuation of reporting.* The requirements of § 98.2(i) do not apply to this subpart. Once a well or group of wells is subject to the requirements of this subpart, the owner or operator must continue for each year thereafter to comply with all requirements of this subpart, including the requirement to submit annual reports, until the Administrator has issued a final decision on an owner or operator's request to discontinue reporting.

(1) *Timing of request.* The owner or operator of a facility may submit a request to discontinue reporting any time after the well or group of wells is plugged and abandoned in accordance with applicable requirements.

(2) *Content of request.* A request for discontinuation of reporting must contain either paragraph (b)(2)(i) or (b)(2)(ii) of this section.

(i) For wells permitted as Class VI under the Underground Injection Control program, a copy of the applicable Underground Injection Control program Director's authorization of site closure.

(ii) For all other wells, and as an alternative for wells permitted as Class VI under the Underground Injection Control program, a demonstration that current monitoring and model(s) show that the injected CO_2 stream is not expected to migrate in the future in a manner likely to result in surface leakage.

(3) *Notification.* The Administrator will issue a final decision on the request to discontinue reporting within a reasonable time. Any appeal of the Administrator's final decision is subject to the provisions of part 78 of this chapter.

§ 98.442 GHGs to report.

You must report:

(a) Mass of CO_2 received.

(b) Mass of CO_2 injected into the subsurface.

(c) Mass of CO_2 produced.

(d) Mass of CO_2 emitted by surface leakage.

(e) Mass of CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment located between the injection flow meter and the injection wellhead.

(f) Mass of CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment located between the production flow meter and the production wellhead.

(g) Mass of CO_2 sequestered in subsurface geologic formations.

(h) Cumulative mass of CO_2 reported as sequestered in subsurface geologic formations in all years since the facility became subject to reporting requirements under this subpart.

[75 FR 75078, Dec. 1, 2010, as amended at 76 FR 73905, Nov. 29, 2011]

§ 98.443 Calculating CO_2 geologic sequestration.

You must calculate the mass of CO_2 received using CO_2 received equations (Equations RR–1 to RR–3 of this section), unless you follow the procedures in § 98.444(a)(4). You must calculate CO_2 sequestered using injection equations (Equations RR–4 to RR–6 of this section), production/recycling equations (Equations RR–7 to RR–9 of this section), surface leakage equations (Equation RR–10 of this section), and sequestration equations (Equations RR–11 and RR–12 of this section). For your first year of reporting, you must calculate CO_2 sequestered starting from the date set forth in your approved MRV plan.

(a) You must calculate and report the annual mass of CO_2 received by pipeline using the procedures in paragraphs (a)(1) or (a)(2) of this section and the procedures in paragraph (a)(3) of this section, if applicable.

(1) For a mass flow meter, you must calculate the total annual mass of CO_2 in a CO_2 stream received in metric tons by multiplying the mass flow by the CO_2 concentration in the flow, according to Equation RR–1 of this section. You must collect these data quarterly. Mass flow and concentration data measurements must be made in accordance with § 98.444.

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \qquad \text{(Eq. RR-1)}$$

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

(2) For a volumetric flow meter, you must calculate the total annual mass of CO_2 in a CO_2 stream received in metric tons by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation RR–2 of this section. You must collect these data quarterly. Volumetric flow and concentration data measurements must be made in accordance with § 98.444.

$$CO_{2T,r} = \sum_{p=1}^{4} (Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \qquad \text{(Eq. RR-2)}$$

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

(3) If you receive CO_2 through more than one flow meter, you must sum the mass of all CO_2 received in accordance with the procedure specified in Equation RR–3 of this section.

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \quad \text{(Eq. RR-3)}$$

where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation RR–1 or RR–2 for flow meter r.

r = Receiving flow meter.

(b) You must calculate and report the annual mass of CO_2 received in containers using the procedures in paragraphs (b)(1) or (b)(2) of this section.

(1) If you are measuring the mass of contents in a container under the provisions of § 98.444(a)(2)(i), you must calculate the CO_2 received for injection in containers using Equation RR–1 of this section.

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

$Q_{r,p}$ = Quarterly mass of contents in containers r in quarter p (metric tons).

$S_{r,p}$ = Quarterly volume of contents in containers r redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

p = Quarter of the year.

r = Containers.

(2) If you are measuring the volume of contents in a container under the provisions of § 98.444(a)(2)(ii), you must calculate the CO_2 received for injection in containers using Equation RR–2 of this section.

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received in containers r (metric tons).

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

$Q_{r,p}$ = Quarterly volume of contents in containers r in quarter p (standard cubic meters).

$S_{r,p}$ = Quarterly mass of contents in containers r redelivered to another facility without being injected into your well in quarter p (metric tons).

D = Density of the CO_2 received in containers at standard conditions (metric tons per standard cubic meter):0.0018682.

p = Quarter of the year.

r = Containers.

(c) You must report the annual mass of CO_2 injected in accordance with the procedures specified in paragraphs (c)(1) through (c)(3) of this section.

(1) If you use a mass flow meter to measure the flow of an injected CO_2 stream, you must calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the mass flow by the CO_2 concentration in the flow, according to Equation RR–4 of this section. Mass flow and concentration data measurements must be made in accordance with § 98.444.

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * C_{CO_{2,p,u}} \quad \text{(Eq. RR-4)}$$

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly mass flow rate measurement for flow meter u in quarter p (metric tons per quarter).

$C_{CO2,p,u}$ = Quarterly CO_2 concentration measurement in flow for flow meter u in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

(2) If you use a volumetric flow meter to measure the flow of an injected CO_2 stream, you must calculate annually the total mass of CO_2 (in metric tons) in the CO_2 stream injected each year in metric tons by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and

the density of CO_2 at standard conditions, according to Equation RR–5 of this section. Volumetric flow and concentration data measurements must be made in accordance with §98.444.

$$CO_{2,u} = \sum_{p=1}^{4} Q_{p,u} * D * C_{CO_{2,p,u}} \quad \text{(Eq. RR-5)}$$

where:

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

$Q_{p,u}$ = Quarterly volumetric flow rate measurement for flow meter u in quarter p at standard conditions (standard cubic meters per quarter).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO2,p,u}$ = CO_2 concentration measurement in flow for flow meter u in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

u = Flow meter.

(3) To aggregate injection data for all wells covered under this subpart, you must sum the mass of all CO_2 injected through all injection wells in accordance with the procedure specified in Equation RR–6 of this section.

$$CO_{2I} = \sum_{u=1}^{U} CO_{2,u} \quad \text{(Eq. RR-6)}$$

where:

CO_{2I} = Total annual CO_2 mass injected (metric tons) through all injection wells.

$CO_{2,u}$ = Annual CO_2 mass injected (metric tons) as measured by flow meter u.

u = Flow meter.

(d) You must calculate the annual mass of CO_2 produced from oil or gas production wells or from other fluid wells for each separator that sends a stream of gas into a recycle or end use system in accordance with the procedures specified in paragraphs (d)(1) through (d)(3) of this section. You must account for any CO_2 that is produced and not processed through a separator. You must account only for wells that produce the CO_2 that was injected into the well or wells covered by this source category.

(1) For each gas-liquid separator for which flow is measured using a mass flow meter, you must calculate annually the total mass of CO_2 produced from an oil or other fluid stream in metric tons that is separated from the fluid by multiplying the mass gas flow by the CO_2 concentration in the gas flow, according to Equation RR–7 of this section. You must collect these data quarterly. Mass flow and concentration data measurements must be made in accordance with §98.444.

$$CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} * C_{CO_{2,p,w}} \quad \text{(Eq. RR-7)}$$

Where:

$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.

$Q_{p,w}$ = Quarterly gas mass flow rate measurement for separator w in quarter p (metric tons).

$C_{CO2,p,w}$ = Quarterly CO_2 concentration measurement in flow for separator w in quarter p (wt. percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
w = Separator.

(2) For each gas-liquid separator for which flow is measured using a volumetric flow meter, you must calculate annually the total mass of CO_2 produced from an oil or other fluid stream in metric tons that is separated from the fluid by multiplying the volumetric gas flow at standard conditions by the CO_2 concentration in the gas flow and the density of CO_2 at standard conditions, according to Equation RR–8 of this section. You must collect these data quarterly. Volumetric flow and concentration data measurements must be made in accordance with § 98.444.

$$CO_{2,w} = \sum_{p=1}^{4} Q_{p,w} * D * C_{CO_{2,p,w}} \qquad \text{(Eq. RR-8)}$$

Where:
$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w.
$Q_{p,w}$ = Volumetric gas flow rate measurement for separator w in quarter p at standard conditions (standard cubic meters).
D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.
$C_{CO2,p,w}$ = CO_2 concentration measurement in flow for separator w in quarter p (vol. percent CO_2, expressed as a decimal fraction).
p = Quarter of the year.
w = Separator.

(3) To aggregate production data, you must sum the mass of all of the CO_2 separated at each gas-liquid separator in accordance with the procedure specified in Equation RR–9 of this section. You must assume that the total CO_2 measured at the separator(s) represents a percentage of the total CO_2 produced. In order to account for the percentage of CO_2 produced that is estimated to remain with the produced oil or other fluid, you must multiply the quarterly mass of CO_2 measured at the separator(s) by a percentage estimated using a methodology in your approved MRV plan. If fluids containing CO_2 from injection wells covered under this source category are produced and not processed through a gas-liquid separator, the concentration of CO_2 in the produced fluids must be measured at a flow meter located prior to reinjection or reuse using methods in § 98.444(f)(1). The considerations you intend to use to calculate CO_2 from produced fluids for the mass balance equation must be described in your approved MRV plan in accordance with § 98.448(a)(5).

$$CO_{2P} = (1+X) * \sum_{w=1}^{W} CO_{2,w} \qquad \text{(Eq. RR-9)}$$

Where:
CO_{2P} = Total annual CO_2 mass produced (metric tons) through all separators in the reporting year.
$CO_{2,w}$ = Annual CO_2 mass produced (metric tons) through separator w in the reporting year.
X = Entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2, expressed as a decimal fraction).
w = Separator.

(e) You must report the annual mass of CO_2 that is emitted by surface leakage in accordance with your approved MRV plan. You must calculate the total annual mass of CO_2 emitted from all leakage pathways in accordance with the procedure specified in Equation RR–10 of this section.

$$CO_{2E} = \sum_{x=1}^{X} CO_{2,x} \quad \text{(Eq. RR-10)}$$

where:

CO_{2E} = Total annual CO_2 mass emitted by surface leakage (metric tons) in the reporting year.

$CO_{2,x}$ = Annual CO_2 mass emitted (metric tons) at leakage pathway x in the reporting year.

x = Leakage pathway.

(f) You must report the annual mass of CO_2 that is sequestered in subsurface geologic formations in the reporting year in accordance with the procedures specified in paragraphs (f)(1) and (f)(2) of this section.

(1) If you are actively producing oil or natural gas or if you are producing any other fluids, you must calculate the annual mass of CO_2 that is sequestered in the underground subsurface formation in the reporting year in accordance with the procedure specified in Equation RR–11 of this section.

$$CO_2 = CO_{2I} - CO_{2P} - CO_{2E} - CO_{2FI} - CO_{2FP} \quad \text{(Eq. RR-11)}$$

where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

CO_{2P} = Total annual CO_2 mass produced (metric tons) in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of this part.

CO_{2FP} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity, for which a calculation procedure is provided in subpart W of this part.

(2) If you are not actively producing oil or natural gas or any other fluids, you must calculate the annual mass of CO_2 that is sequestered in subsurface geologic formations in the reporting year in accordance with the procedures specified in Equation RR–12 of this section.

$$CO_2 = CO_{2I} - CO_{2E} - CO_{2FI} \quad \text{(Eq. RR-12)}$$

where:

CO_2 = Total annual CO_2 mass sequestered in subsurface geologic formations (metric tons) at the facility in the reporting year.

CO_{2I} = Total annual CO_2 mass injected (metric tons) in the well or group of wells covered by this source category in the reporting year.

CO_{2E} = Total annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year.

CO_{2FI} = Total annual CO_2 mass emitted (metric tons) from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead, for which a calculation procedure is provided in subpart W of this part.

[75 FR 75078, Dec. 1, 2010, as amended at 76 FR 73906, Nov. 29, 2011; 78 FR 71978, Nov. 29, 2013]

§ 98.444 Monitoring and QA/QC requirements.

(a) *CO_2 received.* (1) Except as provided in paragraph (a)(4) of this section, you must determine the quarterly flow rate of CO_2 received by pipeline by following the most appropriate of the following procedures:

(i) You may measure flow rate at the receiving custody transfer meter prior to any subsequent processing operations at the facility and collect the flow rate quarterly.

(ii) If you took ownership of the CO_2 in a commercial transaction, you may use the quarterly flow rate data from the sales contract if it is a one-time transaction or from invoices or manifests if it is an ongoing commercial transaction with discrete shipments.

(iii) If you inject CO_2 received from a production process unit that is part of your facility, you may use the quarterly CO_2 flow rate that was measured at the equivalent of a custody transfer meter following procedures provided in subpart PP of this part. To be the equivalent of a custody transfer meter, a meter must measure the flow of CO_2 being transported to an injection well to the same degree of accuracy as a meter used for commercial transactions.

(2) Except as provided in paragraph (a)(4) of this section, you must determine the quarterly mass or volume of contents in all containers if you receive CO_2 in containers by following the most appropriate of the following procedures:

(i) You may measure the mass of contents of containers summed quarterly using weigh bills, scales, or load cells.

(ii) You may determine the volume of the contents of containers summed quarterly.

(iii) If you took ownership of the CO_2 in a commercial transaction, you may use the quarterly mass or volume of contents from the sales contract if it is a one-time transaction or from invoices or manifests if it is an ongoing commercial transaction with discrete shipments.

(3) Except as provided in paragraph (a)(4) of this section, you must determine a quarterly concentration of the CO_2 received that is representative of all CO_2 received in that quarter by following the most appropriate of the following procedures:

(i) You may sample the CO_2 stream at least once per quarter at the point of receipt and measure its CO_2 concentration.

(ii) If you took ownership of the CO_2 in a commercial transaction for which the sales contract was contingent on CO_2 concentration, and if the supplier of the CO_2 sampled the CO_2 stream in a quarter and measured its concentration per the sales contract terms, you may use the CO_2 concentration data from the sales contract for that quarter.

(iii) If you inject CO_2 from a production process unit that is part of your facility, you may report the quarterly CO_2 concentration of the CO_2 stream supplied that was measured following the procedures provided in subpart PP of this part.

(4) If the CO_2 you receive is wholly injected and is not mixed with any other supply of CO_2, you may report the annual mass of CO_2 injected that you determined following the requirements under paragraph (b) of this section as the total annual mass of CO_2 received instead of using Equation RR–1 or RR–2 of this subpart to calculate CO_2 received.

(5) You must assume that the CO_2 you receive meets the definition of a CO_2 stream unless you can trace it through written records to a source other than a CO_2 stream.

(b) *CO_2 injected.* (1) You must select a point or points of measurement at which the CO_2 stream(s) is representative of the CO_2 stream(s) being injected. You may use as the point or points of measurement the location(s) of the flow meter(s) used to comply with the flow monitoring and reporting provisions in your Underground Injection Control permit.

(2) You must measure flow rate of CO_2 injected with a flow meter and collect the flow rate quarterly.

(3) You must sample the injected CO_2 stream at least once per quarter immediately upstream or downstream of the flow meter used to measure flow rate of that CO_2 stream and measure the CO_2 concentration of the sample.

(c) *CO_2 produced.* (1) The point of measurement for the quantity of CO_2

produced from oil or other fluid production wells is a flow meter directly downstream of each separator that sends a stream of gas into a recycle or end use system.

(2) You must sample the produced gas stream at least once per quarter immediately upstream or downstream of the flow meter used to measure flow rate of that gas stream and measure the CO_2 concentration of the sample.

(3) You must measure flow rate of gas produced with a flow meter and collect the flow rate quarterly.

(d) *CO_2 emissions from equipment leaks and vented emissions of CO_2.* If you have equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead or between the flow meter used to measure production quantity and the production wellhead, you must follow the monitoring and QA/QC requirements specified in subpart W of this part for the equipment.

(e) *Measurement devices.* (1) All flow meters must be operated continuously except as necessary for maintenance and calibration.

(2) You must calibrate all flow meters used to measure quantities reported in § 98.446 according to the calibration and accuracy requirements in § 98.3(i).

(3) You must operate all measurement devices according to one of the following. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(4) You must ensure that any flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

(f) *General.* (1) If you measure the concentration of any CO_2 quantity for reporting, you must measure according to one of the following. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice.

(2) You must convert all measured volumes of CO_2 to the following standard industry temperature and pressure conditions for use in Equations RR–2, RR–5 and RR–8 of this subpart: Standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere.

(3) For 2011, you may follow the provisions of § 98.3(d)(1) through (2) for best available monitoring methods only for parameters required by paragraphs (a) and (b) of § 98.443 rather than follow the monitoring requirements of paragraph (a) of this section. For purposes of this subpart, any reference to the year 2010 in § 98.3(d)(1) through (2) shall mean 2011.

[75 FR 75078, Dec. 1, 2010, as amended at 76 FR 73906, Nov. 29, 2011]

§ 98.445 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG quantities calculations is required. Whenever the monitoring procedures cannot be followed, you must use the following missing data procedures:

(a) A quarterly flow rate of CO_2 received that is missing must be estimated as follows:

(1) Another calculation methodology listed in § 98.444(a)(1) must be used if possible.

(2) If another method listed in § 98.444(a)(1) cannot be used, a quarterly flow rate value that is missing must be estimated using a representative flow rate value from the nearest previous time period.

(b) A quarterly mass or volume of contents in containers received that is missing must be estimated as follows:

(1) Another calculation methodology listed in § 98.444(a)(2) must be used if possible.

(2) If another method listed in § 98.444(a)(2) cannot be used, a quarterly mass or volume value that is missing must be estimated using a representative mass or volume value from the nearest previous time period.

(c) A quarterly CO_2 concentration of a CO_2 stream received that is missing must be estimated as follows:

(1) Another calculation methodology listed in § 98.444(a)(3) must be used if possible.

(2) If another method listed in § 98.444(a)(3) cannot be used, a quarterly concentration value that is missing must be estimated using a representative concentration value from the nearest previous time period.

(d) A quarterly quantity of CO_2 injected that is missing must be estimated using a representative quantity of CO_2 injected from the nearest previous period of time at a similar injection pressure.

(e) For any values associated with CO_2 emissions from equipment leaks and vented emissions of CO_2 from surface equipment at the facility that are reported in this subpart, missing data estimation procedures should be followed in accordance with those specified in subpart W of this part.

(f) The quarterly quantity of CO_2 produced from subsurface geologic formations that is missing must be estimated using a representative quantity of CO_2 produced from the nearest previous period of time.

(g) You must estimate the mass of CO_2 emitted by surface leakage that is missing as required by your approved MRV plan.

(h) You must estimate other missing data as required by your approved MRV plan.

[75 FR 75078, Dec. 1, 2010, as amended at 76 FR 73906, Nov. 29, 2011]

§ 98.446 Data reporting requirements.

In addition to the information required by § 98.3(c), report the information listed in this section.

(a) If you receive CO_2 by pipeline, report the following for each receiving flow meter:

(1) The total net mass of CO_2 received (metric tons) annually.

(2) If a volumetric flow meter is used to receive CO_2 report the following unless you reported yes to paragraph (a)(4) of this section:

(i) The volumetric flow through a receiving flow meter at standard conditions (in standard cubic meters) in each quarter.

(ii) The volumetric flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in standard cubic meters) in each quarter.

(iii) The CO_2 concentration in the flow (volume percent CO_2 expressed as a decimal fraction) in each quarter.

(3) If a mass flow meter is used to receive CO_2 report the following unless you reported yes to paragraph (a)(4) of this section:

(i) The mass flow through a receiving flow meter (in metric tons) in each quarter.

(ii) The mass flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in metric tons) in each quarter.

(iii) The CO_2 concentration in the flow (weight percent CO_2 expressed as a decimal fraction) in each quarter.

(4) If the CO_2 received is wholly injected and not mixed with any other supply of CO_2, report whether you followed the procedures in § 98.444(a)(4).

(5) The standard or method used to calculate each value in paragraphs (a)(2) through (a)(3) of this section.

(6) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (a)(2) through (a)(3) of this section.

(7) Whether the flow meter is mass or volumetric.

(8) A numerical identifier for the flow meter.

(b) If you receive CO_2 in containers, report:

(1) The mass (in metric tons) or volume at standard conditions (in standard cubic meters) of contents in containers received in each quarter.

(2) The concentration of CO_2 of contents in containers (volume or wt. percent CO_2 expressed as a decimal fraction) in each quarter.

(3) The mass (in metric tons) or volume (in standard cubic meters) of contents in containers that is redelivered to another facility without being injected into your well in each quarter.

(4) The net mass of CO_2 received (in metric tons) annually.

(5) The standard or method used to calculate each value in paragraphs (b)(1), (b)(2), and (b)(3) of this section.

(6) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (b)(1) and (b)(2) of this section.

(c) If you use more than one receiving flow meter, report the total net mass of CO_2 received (metric tons) through all flow meters annually.

(d) The source of the CO_2 received according to the following categories:

(1) CO_2 production wells.

(2) Electric generating unit.

(3) Ethanol plant.

(4) Pulp and paper mill.

(5) Natural gas processing.

(6) Gasification operations.

(7) Other anthropogenic source.

(8) Discontinued enhanced oil and gas recovery project.

(9) Unknown.

(e) Report the date that you began collecting data for calculating total amount sequestered according to § 98.448(a)(7) of this subpart.

(f) Report the following. If the date specified in paragraph (e) of this section is during the reporting year for this annual report, report the following starting on the date specified in paragraph (e) of this section.

(1) For each injection flow meter (mass or volumetric), report:

(i) The mass of CO_2 injected (metric tons) annually.

(ii) The CO_2 concentration in flow (volume or weight percent CO_2 expressed as a decimal fraction) in each quarter.

(iii) If a volumetric flow meter is used, the volumetric flow rate at standard conditions (in standard cubic meters) in each quarter.

(iv) If a mass flow meter is used, the mass flow rate (in metric tons) in each quarter.

(v) A numerical identifier for the flow meter.

(vi) Whether the flow meter is mass or volumetric.

(vii) The standard used to calculate each value in paragraphs (f)(1)(ii) through (f)(1)(iv) of this section.

(viii) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (f)(1)(ii) through (f)(1)(iv) of this section.

(ix) The location of the flow meter.

(2) The total CO_2 injected (metric tons) in the reporting year as calculated in Equation RR–6 of this subpart.

(3) For CO_2 emissions from equipment leaks and vented emissions of CO_2, report the following:

(i) The mass of CO_2 emitted (in metric tons) annually from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(ii) The mass of CO_2 emitted (in metric tons) annually from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the production wellhead and the flow meter used to measure production quantity.

(4) For each separator flow meter (mass or volumetric), report:

(i) CO_2 mass produced (metric tons) annually.

(ii) CO_2 concentration in flow (volume or weight percent CO_2 expressed as a decimal fraction) in each quarter.

(iii) If a volumetric flow meter is used, volumetric flow rate at standard conditions (standard cubic meters) in each quarter.

(iv) If a mass flow meter, mass flow rate (metric tons) in each quarter.

(v) A numerical identifier for the flow meter.

(vi) Whether the flow meter is mass or volumetric.

(vii) The standard used to calculate each value in paragraphs (f)(4)(ii) through (f)(4)(iv) of this section.

(viii) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (f)(4)(ii) through (f)(4)(iv) of this section.

(5) The entrained CO_2 in produced oil or other fluid divided by the CO_2 separated through all separators in the reporting year (weight percent CO_2 expressed as a decimal fraction) used as the value for X in Equation RR–9 of this subpart and as determined according to your EPA-approved MRV plan.

(6) Annual CO_2 produced in the reporting year as calculated in Equation RR–9 of this subpart.

(7) For each leakage pathway through which CO_2 emissions occurred, report:

(i) A numerical identifier for the leakage pathway.

(ii) The CO_2 (metric tons) emitted through that pathway in the reporting year.

(8) Annual CO_2 mass emitted (metric tons) by surface leakage in the reporting year as calculated by Equation RR–10 of this subpart.

(9) Annual CO_2 (metric tons) sequestered in subsurface geologic formations in the reporting year as calculated by Equation RR–11 or RR–12 of this subpart.

(10) Cumulative mass of CO_2 (metric tons) reported as sequestered in subsurface geologic formations in all years since the well or group of wells became subject to reporting requirements under this subpart.

(11) Date that the most recent MRV plan was approved by EPA and the MRV plan approval number that was issued by EPA.

(12) An annual monitoring report that contains the following components:

(i) A narrative history of the monitoring efforts conducted over the previous calendar year, including a listing of all monitoring equipment that was operated, its period of operation, and any relevant tests or surveys that were conducted.

(ii) A description of any changes to the monitoring program that you concluded were not material changes warranting submission of a revised MRV plan under §98.448(d).

(iii) A narrative history of any monitoring anomalies that were detected in the previous calendar year and how they were investigated and resolved.

(iv) A description of any surface leakages of CO_2, including a discussion of all methodologies and technologies involved in detecting and quantifying the surface leakages and any assumptions and uncertainties involved in calculating the amount of CO_2 emitted.

(13) If a well is permitted under the Underground Injection Control program, for each injection well, report:

(i) The well identification number used for the Underground Injection Control permit.

(ii) The Underground Injection Control permit class.

(14) If an offshore well is not subject to the Safe Drinking Water Act, for each injection well, report any well identification number and any identification number used for the legal instrument authorizing geologic sequestration.

[75 FR 75078, Dec. 1, 2010, as amended at 76 FR 73906, Nov. 29, 2011; 78 FR 71979, Nov. 29, 2013]

§98.447 Records that must be retained.

(a) You must follow the record retention requirements specified by §98.3(g). In addition to the records required by §98.3(g), you must retain the records specified in paragraphs (a)(1) through (7) of this section, as applicable. You must retain all required records for at least 3 years.

(1) Quarterly records of CO_2 received, including mass flow rate of contents of containers (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(2) Quarterly records of produced CO_2, including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(3) Quarterly records of injected CO_2 including mass flow or volumetric flow at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams.

(4) Annual records of information used to calculate the CO_2 emitted by surface leakage from leakage pathways.

(5) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the surface between the flow meter used to measure injection quantity and the injection wellhead.

(6) Annual records of information used to calculate the CO_2 emitted from equipment leaks and vented emissions of CO_2 from equipment located on the

surface between the production wellhead and the flow meter used to measure production quantity.

(7) Any other records as specified for retention in your EPA-approved MRV plan.

(b) You must complete your monitoring plans, as described in § 98.3(g)(5), by April 1 of the year you begin collecting data.

[75 FR 75078, Dec. 1, 2010, as amended at 76 FR 73906, Nov. 29, 2011]

§ 98.448 Geologic sequestration monitoring, reporting, and verification (MRV) plan.

(a) *Contents of MRV plan.* You must develop and submit to the Administrator a proposed MRV plan for monitoring, reporting, and verification of geologic sequestration at your facility. Your proposed MRV plan must contain the following components:

(1) Delineation of the maximum monitoring area and the active monitoring areas. The first period for your active monitoring area will begin from the date determined in your MRV plan through the date at which the plan calls for the first expansion of the monitoring area. The length of each monitoring period can be any time interval chosen by you that is greater than 1 year.

(2) Identification of potential surface leakage pathways for CO_2 in the maximum monitoring area and the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways.

(3) A strategy for detecting and quantifying any surface leakage of CO_2.

(4) A strategy for establishing the expected baselines for monitoring CO_2 surface leakage.

(5) A summary of the considerations you intend to use to calculate site-specific variables for the mass balance equation. This includes, but is not limited to, considerations for calculating CO_2 emissions from equipment leaks and vented emissions of CO_2 between the injection flow meter and injection well and/or the production flow meter and production well, and considerations for calculating CO_2 in produced fluids.

(6) If a well is permitted under the Underground Injection Control program, for each injection well, report the well identification number used for the Underground Injection Control permit and the Underground Injection Control permit class. If the well is not yet permitted, and you have applied for an Underground Injection Control permit, report the well identification numbers in the permit application. If an offshore well is not subject to the Safe Drinking Water Act, for each injection well, report any well identification number and any identification number used for the legal instrument authorizing geologic sequestration. If you are submitting your Underground Injection Control permit application as part of your proposed MRV plan, you must notify EPA when the permit has been approved. If you are an offshore facility not subject to the Safe Drinking Water Act, and are submitting your application for the legal instrument authorizing geologic sequestration as part of your proposed MRV plan, you must notify EPA when the legal instrument authorizing geologic sequestration has been approved.

(7) Proposed date to begin collecting data for calculating total amount sequestered according to equation RR–11 or RR–12 of this subpart. This date must be after expected baselines as required by paragraph (a)(4) of this section are established and the leakage detection and quantification strategy as required by paragraph (a)(3) of this section is implemented in the initial AMA.

(b) *Timing.* You must submit a proposed MRV plan to EPA according to the following schedule:

(1) You must submit a proposed MRV plan to EPA by June 30, 2011 if you were issued a final Underground Injection Control permit authorizing the injection of CO_2 into the subsurface on or before December 31, 2010. You will be allowed to request one extension of up to an additional 180 days in which to submit your proposed MRV plan.

(2) You must submit a proposed MRV plan to EPA within 180 days of receiving a final Underground Injection Control permit authorizing the injection of CO_2 into the subsurface. If your facility is an offshore facility not subject to the Safe Drinking Water Act, you must submit a proposed MRV plan to EPA

within 180 days of receiving authorization to begin geologic sequestration of CO_2. You will be allowed to request one extension of the submittal date of up to an additional 180 days.

(3) If you are injecting a CO_2 stream in subsurface geologic formations to enhance the recovery of oil or natural gas and you are not permitted as Class VI under the Underground Injection Control program, you may opt to submit an MRV plan at any time.

(4) If EPA determines that your proposed MRV plan is incomplete, you must submit an updated MRV plan within 45 days of EPA notification, unless otherwise specified by EPA.

(c) *Final MRV plan.* The Administrator will issue a final MRV plan within a reasonable period of time. The Administrator's final MRV plan is subject to the provisions of part 78 of this chapter. Once the MRV plan is final and no longer subject to administrative appeal under part 78 of this chapter, you must implement the plan starting on the day after the day on which the plan becomes final and is no longer subject to such appeal.

(d) *MRV plan revisions.* You must revise and submit the MRV plan within 180 days to the Administrator for approval if any of the following in paragraphs (d)(1) through (d)(4) of this section applies. You must include the reason(s) for the revisions in your submittal.

(1) A material change was made to monitoring and/or operational parameters that was not anticipated in the original MRV plan. Examples of material changes include but are not limited to: Large changes in the volume of CO_2 injected; the construction of new injection wells not identified in the MRV plan; failures of the monitoring system including monitoring system sensitivity, performance, location, or baseline; changes to surface land use that affects baseline or operational conditions; observed plume location that differs significantly from the predicted plume area used for developing the MRV plan; a change in the maximum monitoring area or active monitoring area; or a change in monitoring technology that would result in coverage or detection capability different from the MRV plan.

(2) A change in the permit class of your Underground Injection Control permit.

(3) If you are notified by EPA of substantive errors in your MRV plan or monitoring report.

(4) You choose to revise your MRV plan for any other reason in any reporting year.

(e) *Revised MRV plan.* The requirements of paragraph (c) of this section apply to any submission of a revised MRV plan. You must continue reporting under your currently approved plan while awaiting approval of a revised MRV plan.

(f) *Format.* Each proposed MRV plan or revision and each annual report must be submitted electronically in a format specified by the Administrator.

(g) *Certificate of representation.* You must submit a certificate of representation according to the provisions in §98.4 at least 60 days before submission of your MRV plan, your research and development exemption request, your MRV plan submission extension request, or your initial annual report under this part, whichever is earlier.

[75 FR 75078, Dec. 1, 2010, as amended at 76 FR 73907, Nov. 29, 2011]

§ 98.449 Definitions.

Except as provided below, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

Active monitoring area is the area that will be monitored over a specific time interval from the first year of the period (n) to the last year in the period (t). The boundary of the active monitoring area is established by superimposing two areas:

(1) The area projected to contain the free phase CO_2 plume at the end of year t, plus an all around buffer zone of one-half mile or greater if known leakage pathways extend laterally more than one-half mile.

(2) The area projected to contain the free phase CO_2 plume at the end of year t+5.

CO_2 received means the CO_2 stream that you receive to be injected for the first time into a well on your facility that is covered by this subpart. CO_2 received includes, but is not limited to, a CO_2 stream from a production process

unit inside your facility and a CO_2 stream that was injected into a well on another facility, removed from a discontinued enhanced oil or natural gas or other production well, and transferred to your facility.

Equipment leak means those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening.

Expected baseline is the anticipated value of a monitored parameter that is compared to the measured monitored parameter.

Maximum monitoring area means the area that must be monitored under this regulation and is defined as equal to or greater than the area expected to contain the free phase CO_2 plume until the CO_2 plume has stabilized plus an all-around buffer zone of at least one-half mile.

Research and development project means a project for the purpose of investigating practices, monitoring techniques, or injection verification, or engaging in other applied research, that will enable safe and effective long-term containment of a CO_2 stream in subsurface geologic formations, including research and short duration CO_2 injection tests conducted as a precursor to long-term storage.

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

Surface leakage means the movement of the injected CO_2 stream from the injection zone to the surface, and into the atmosphere, indoor air, oceans, or surface water.

Underground Injection Control permit means a permit issued under the authority of Part C of the Safe Drinking Water Act at 42 U.S.C. 300h *et seq.*

Underground Injection Control program means the program responsible for regulating the construction, operation, permitting, and closure of injection wells that place fluids underground for storage or disposal for purposes of protecting underground sources of drinking water from endangerment pursuant to Part C of the Safe Drinking Water Act at 42 U.S.C. 300h *et seq.*

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

[75 FR 75078, Dec. 1, 2010, as amended at 76 FR 73907, Nov. 29, 2011]

Subpart SS—Electrical Equipment Manufacture or Refurbishment

SOURCE: 75 FR 74859, Dec. 1, 2010, unless otherwise noted.

§ 98.450 Definition of the source category.

The electrical equipment manufacturing or refurbishment category consists of processes that manufacture or refurbish gas-insulated substations, circuit breakers, other switchgear, gas-insulated lines, or power transformers (including gas-containing components of such equipment) containing sulfur-hexafluoride (SF_6) or perfluorocarbons (PFCs). The processes include equipment testing, installation, manufacturing, decommissioning and disposal, refurbishing, and storage in gas cylinders and other containers.

§ 98.451 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an electrical equipment manufacturing or refurbishing process and the facility meets the requirements of § 98.2(a)(1). Electrical equipment manufacturing and refurbishing facilities covered by this rule are those that have total annual purchases of SF_6 and PFCs that exceed 23,000 pounds.

§ 98.452 GHGs to report.

(a) You must report SF_6 and PFC emissions at the facility level. Annual emissions from the facility must include SF_6 and PFC emissions from equipment that is installed at an off-site electric power transmission or distribution location whenever emissions from installation activities (e.g., filling) occur before the title to the equipment is transferred to the electric power transmission or distribution entity.

(b) You must report CO_2, N_2O and CH_4 emissions from each stationary combustion unit. You must calculate and report these emissions under subpart C of this part (General Stationary Fuel Combustion Sources) by following the requirements of subpart C of this part.

§ 98.453 Calculating GHG emissions.

(a) For each electrical equipment manufacturer or refurbisher, estimate the annual SF_6 and PFC emissions using the mass-balance approach in Equation SS–1 of this section:

$$\text{User Emissions} = (\text{Decrease in } SF_6 \text{ Inventory}) + (\text{Acquisitions of } SF_6) - (\text{Disbursements of } SF_6) \quad \text{(Eq. SS-1)}$$

where:

Decrease in SF_6 Inventory = (Pounds of SF_6 stored in containers at the beginning of the year) − (Pounds of SF_6 stored in containers at the end of the year).

Acquisitions of SF_6 = (Pounds of SF_6 purchased from chemical producers or suppliers in bulk) + (Pounds of SF_6 returned by equipment users) + (Pounds of SF_6 returned to site after off-site recycling).

Disbursements of SF_6 = (Pounds of SF_6 contained in new equipment delivered to customers) + (Pounds of SF_6 delivered to equipment users in containers) + (Pounds of SF_6 returned to suppliers) + (Pounds of SF_6 sent off site for recycling) + (Pounds of SF_6 sent off-site for destruction).

(b) Use the mass-balance method in paragraph (a) of this section to estimate emissions of PFCs associated with the manufacture or refurbishment of power transformers, substituting the relevant PFC(s) for SF_6 in Equation SS–1 of this section.

(c) Estimate the disbursements of SF_6 or PFCs sent to customers in new equipment or cylinders or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers using Equation SS–2 of this section:

$$D_{GHG} = \sum_{p=1}^{n} Q_p \quad \text{(Eq. SS-2)}$$

where:

D_{GHG} = The annual disbursement of SF_6 or PFCs sent to customers in new equipment or cylinders or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.

Q_p = The mass of the SF_6 or PFCs charged into equipment or containers over the period p sent to customers or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.

n = The number of periods in the year.

(d) Estimate the mass of SF_6 or PFCs disbursed to customers in new equipment or cylinders over the period p by monitoring the mass flow of the SF_6 or PFCs into the new equipment or cylinders using a flowmeter, or by weighing containers before and after gas from containers is used to fill equipment or cylinders, or by using the nameplate capacity of the equipment.

(e) If the mass of SF_6 or the PFC disbursed to customers in new equipment or cylinders over the period p is estimated by weighing containers before and after gas from containers is used to fill equipment or cylinders, estimate this quantity using Equation SS–3 of this section:

$$Q_p = M_B - M_E - E_L \quad \text{(Eq. SS-3)}$$

where:

Q_p = The mass of SF_6 or the PFC charged into equipment or containers over the period p sent to customers or sent off-site for other purposes including for recycling, for destruction or to be returned to suppliers.

M_B = The mass of the contents of the containers used to fill equipment or cylinders at the beginning of period p.

M_E = The mass of the contents of the containers used to fill equipment or cylinders at the end of period p.

E_L = The mass of SF_6 or the PFC emitted during the period p downstream of the containers used to fill equipment or cylinders and in cases where a flowmeter is used, downstream of the flowmeter during the period p (e.g., emissions from hoses or other flow lines that connect the container to the equipment or cylinder that is being filled).

(f) If the mass of SF_6 or the PFC disbursed to customers in new equipment or cylinders over the period p is determined using a flowmeter, estimate this quantity using Equation SS–4 of this section:

$$Q_p = M_{mr} - E_L \quad \text{(Eq. SS-4)}$$

where:

Q_p = The mass of SF_6 or the PFC charged into equipment or containers over the period p sent to customers or sent offsite for other purposes including for recycling, for destruction or to be returned to suppliers.

M_{mr} = The mass of the SF_6 or the PFC that has flowed through the flowmeter during the period p.

E_L = The mass of SF_6 or the PFC emitted during the period p downstream of the containers used to fill equipment or cylinders and in cases where a flowmeter is used, downstream of the flowmeter during the period p (e.g., emissions from hoses or other flow lines that connect the container to the equipment that is being filled).

(g) Estimate the mass of SF_6 or the PFC emitted during the period p downstream of the containers used to fill equipment or cylinders (e.g., emissions from hoses or other flow lines that connect the container to the equipment or cylinder that is being filled) using Equation SS–5 of this section:

$$E_L = \sum_{i=1}^{n} F_{Ci} \times EF_{Ci} \quad \text{(Eq. SS-5)}$$

where:

E_L = The mass of SF_6 or the PFC emitted during the period p downstream of the containers used to fill equipment or cylinders and in cases where a flowmeter is used, downstream of the flowmeter during the period p (e.g., emissions from hoses or other flow lines that connect the container to the equipment or cylinder that is being filled)

F_{Ci} = The total number of fill operations over the period p for the valve-hose combination Ci.

EF_{Ci} = The emission factor for the valve-hose combination Ci.

n = The number of different valve-hose combinations C used during the period p.

(h) If the mass of SF_6 or the PFC disbursed to customers in new equipment or cylinders over the period p is determined by using the nameplate capacity, or by using the nameplate capacity of the equipment and calculating the partial shipping charge, use the methods in either paragraph (h)(1) or (h)(2) of this section.

(1) Determine the equipment's actual nameplate capacity, by measuring the nameplate capacities of a representative sample of each make and model and calculating the mean value for each make and model as specified at § 98.454(f).

(2) If equipment is shipped with a partial charge, calculate the partial shipping charge by multiplying the nameplate capacity of the equipment by the ratio of the densities of the partial charge to the full charge.

(i) Estimate the annual SF_6 and PFC emissions from the equipment that is installed at an off-site electric power transmission or distribution location before the title to the equipment is transferred by using Equation SS–6 of this section:

$$EI = M_F + M_c - N_I \quad \text{(Eq. SS-6)}$$

where:

EI = Total annual SF_6 or PFC emissions from equipment installation at electric transmission or distribution facilities.

MF = The total annual mass of the SF6 or PFCs, in pounds, used to fill equipment during equipment installation at electric transmission or distribution facilities.

MC = The total annual mass of the SF_6 or PFCs, in pounds, used to charge the equipment prior to leaving the electrical equipment manufacturer facility.

NI = The total annual nameplate capacity of the equipment, in pounds, installed at electric transmission or distribution facilities.

[75 FR 75078, Dec. 1, 2010, as amended at 78 FR 71979, Nov. 29, 2013]

§ 98.454 Monitoring and QA/QC requirements.

(a) For calendar year 2011 monitoring, you may follow the provisions of § 98.3(d)(1) through (d)(2) for best available monitoring methods rather than follow the monitoring requirements of this section. For purposes of this subpart, any reference in § 98.3(d)(1) through (d)(2) to 2010 means 2011, March 31 means June 30, and April 1 means July 1. Any reference to the effective date in § 98.3(d)(1) through (d)(2) means February 28, 2011.

(b) Ensure that all the quantities required by the equations of this subpart have been measured using either flowmeters with an accuracy and precision of ±1 percent of full scale or better or scales with an accuracy and precision of ±1 percent of the filled weight (gas plus tare) of the containers of SF_6 or PFCs that are typically weighed on the scale. For scales that are generally used to weigh cylinders containing 115 pounds of gas when full, this equates to ±1 percent of the sum of 115 pounds and approximately 120 pounds tare, or slightly more than ±2 pounds. Account for the tare weights of the containers. You may accept gas masses or weights provided by the gas supplier e.g., for the contents of cylinders containing new gas or for the heels remaining in cylinders returned to the gas supplier) if the supplier provides documentation verifying that accuracy standards are met; however, you remain responsible for the accuracy of these masses and weights under this subpart.

(c) All flow meters, weigh scales, and combinations of volumetric and density measures that are used to measure or calculate quantities under this subpart must be calibrated using calibration procedures specified by the flowmeter, scale, volumetric or density measure equipment manufacturer. Calibration must be performed prior to the first reporting year. After the initial calibration, recalibration must be performed at the minimum frequency specified by the manufacturer.

(d) For purposes of Equations SS–5 of this subpart, the emission factor for the valve-hose combination (EF_C) must be estimated using measurements and/or engineering assessments or calculations based on chemical engineering principles or physical or chemical laws or properties. Such assessments or calculations may be based on, as applicable, the internal volume of hose or line that is open to the atmosphere during coupling and decoupling activities, the internal pressure of the hose or line, the time the hose or line is open to the atmosphere during coupling and decoupling activities, the frequency with which the hose or line is purged and the flow rate during purges. You must develop a value for EF_c (or use an industry-developed value) for each combination of hose and valve fitting, to use in Equation SS–5 of this subpart. The value for EF_C must be determined for each combination of hose and valve fitting of a given diameter or size. The calculation must be recalculated annually to account for changes to the specifications of the valves or hoses that may occur throughout the year.

(e) Electrical equipment manufacturers and refurbishers must account for SF_6 or PFC emissions that occur as a result of unexpected events or accidental losses, such as a malfunctioning hose or leak in the flow line, during the filling of equipment or containers for disbursement by including these losses in the estimated mass of SF_6 or the

PFC emitted downstream of the container or flowmeter during the period p.

(f) If the mass of SF_6 or the PFC disbursed to customers in new equipment over the period p is determined by assuming that it is equal to the equipment's nameplate capacity or, in cases where equipment is shipped with a partial charge, equal to its partial shipping charge, equipment samples for conducting the nameplate capacity tests must be selected using the following stratified sampling strategy in this paragraph. For each make and model, group the measurement conditions to reflect predictable variability in the facility's filling practices and conditions (e.g., temperatures at which equipment is filled). Then, independently select equipment samples at random from each make and model under each group of conditions. To account for variability, a certain number of these measurements must be performed to develop a robust and representative average nameplate capacity (or shipping charge) for each make, model, and group of conditions. A Student T distribution calculation should be conducted to determine how many samples are needed for each make, model, and group of conditions as a function of the relative standard deviation of the sample measurements. To determine a sufficiently precise estimate of the nameplate capacity, the number of measurements required must be calculated to achieve a precision of one percent of the true mean, using a 95 percent confidence interval. To estimate the nameplate capacity for a given make and model, you must use the lowest mean value among the different groups of conditions, or provide justification for the use of a different mean value for the group of conditions that represents the typical practices and conditions for that make and model. Measurements can be conducted using SF_6, another gas, or a liquid. Re-measurement of nameplate capacities should be conducted every five years to reflect cumulative changes in manufacturing methods and conditions over time.

(g) Ensure the following QA/QC methods are employed throughout the year:

(1) Procedures are in place and followed to track and weigh all cylinders or other containers at the beginning and end of the year.

(h) You must adhere to the following QA/QC methods for reviewing the completeness and accuracy of reporting:

(1) Review inputs to Equation SS–1 of this subpart to ensure inputs and outputs to the company's system are included.

(2) Do not enter negative inputs and confirm that negative emissions are not calculated. However, the decrease in SF_6 inventory may be calculated as negative.

(3) Ensure that beginning-of-year inventory matches end-of-year inventory from the previous year.

(4) Ensure that in addition to SF_6 purchased from bulk gas distributors, SF_6 returned from equipment users with or inside equipment and SF_6 returned from off-site recycling are also accounted for among the total additions.

§ 98.455 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG emissions calculations is required. Replace missing data, if needed, based on data from similar manufacturing operations, and from similar equipment testing and decommissioning activities for which data are available.

§ 98.456 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each chemical at the facility level:

(a) Pounds of SF_6 and PFCs stored in containers at the beginning of the year.

(b) Pounds of SF_6 and PFCs stored in containers at the end of the year.

(c) Pounds of SF_6 and PFCs purchased in bulk.

(d) Pounds of SF_6 and PFCs returned by equipment users with or inside equipment.

(e) Pounds of SF_6 and PFCs returned to site from off site after recycling.

(f) Pounds of SF_6 and PFCs inside new equipment delivered to customers.

(g) Pounds of SF_6 and PFCs delivered to equipment users in containers.

(h) Pounds of SF_6 and PFCs returned to suppliers.

(i) Pounds of SF_6 and PFCs sent off site for destruction.

(j) Pounds of SF_6 and PFCs sent off site to be recycled.

(k) The nameplate capacity of the equipment, in pounds, delivered to customers with SF_6 or PFCs inside, if different from the quantity in paragraph (f) of this section.

(l) A description of the engineering methods and calculations used to determine emissions from hoses or other flow lines that connect the container to the equipment that is being filled.

(m) The values for EF_{ci} of Equation SS–5 of this subpart for each hose and valve combination and the associated valve fitting sizes and hose diameters.

(n) The total number of fill operations for each hose and valve combination, or, F_{Ci} of Equation SS–5 of this subpart.

(o) If the mass of SF_6 or the PFC disbursed to customers in new equipment over the period p is determined according to the methods required in §98.453(h), report the mean value of nameplate capacity in pounds for each make, model, and group of conditions.

(p) If the mass of SF_6 or the PFC disbursed to customers in new equipment over the period p is determined according to the methods required in §98.453(h), report the number of samples and the upper and lower bounds on the 95 percent confidence interval for each make, model, and group of conditions.

(q) Pounds of SF_6 and PFCs used to fill equipment at off-site electric power transmission or distribution locations, or M_F, of Equation SS–6 of this subpart.

(r) Pounds of SF_6 and PFCs used to charge the equipment prior to leaving the electrical equipment manufacturer or refurbishment facility, or M_C, of Equation SS–6 of this subpart.

(s) The nameplate capacity of the equipment, in pounds, installed at off-site electric power transmission or distribution locations used to determine emissions from installation, or N_I, of Equation SS–6 of this subpart.

(t) For any missing data, you must report the reason the data were missing, the parameters for which the data were missing, the substitute parameters used to estimate emissions in their absence, and the quantity of emissions thereby estimated.

[75 FR 75078, Dec. 1, 2010, as amended at 78 FR 71979, Nov. 29, 2013]

§ 98.457 Records that must be retained.

In addition to the information required by §98.3(g), you must retain the following records:

(a) All information reported and listed in §98.456.

(b) Accuracy certifications and calibration records for all scales and monitoring equipment, including the method or manufacturer's specification used for calibration.

(c) Certifications of the quantity of gas, in pounds, charged into equipment at the electrical equipment manufacturer or refurbishment facility as well as the actual quantity of gas, in pounds, charged into equipment at installation.

(d) Check-out and weigh-in sheets and procedures for cylinders.

(e) Residual gas amounts, in pounds, in cylinders sent back to suppliers.

(f) Invoices for gas purchases and sales.

(g) GHG Monitoring Plans, as described in §98.3(g)(5), must be completed by April 1, 2011.

§ 98.458 Definitions.

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

Subpart TT—Industrial Waste Landfills

SOURCE: 75 FR 39773, July 12, 2010, unless otherwise noted.

§ 98.460 Definition of the source category.

(a) This source category applies to industrial waste landfills that accepted waste on or after January 1, 1980, and that are located at a facility whose total landfill design capacity is greater than or equal to 300,000 metric tons.

(b) *An industrial waste landfill* is a landfill other than a municipal solid waste landfill, a RCRA Subtitle C hazardous waste landfill, or a TSCA hazardous waste landfill, in which industrial solid waste, such as RCRA Subtitle D wastes (non-hazardous industrial solid waste, defined in 40 CFR 257.2), commercial solid wastes, or conditionally exempt small quantity generator wastes, is placed. An industrial waste landfill includes all disposal areas at the facility.

(c) This source category does not include:

(1) Construction and demolition waste landfills.

(2) Industrial waste landfills that only receive one or more of the following inert waste materials:

(i) Coal combustion or incinerator ash (*e.g.*, fly ash).

(ii) Cement kiln dust.

(iii) Rocks and/or soil from excavation and construction and similar activities.

(iv) Glass.

(v) Non-chemically bound sand (*e.g.*, green foundry sand).

(vii) Clay, gypsum, or pottery cull.

(viii) Bricks, mortar, or cement.

(ix) Furnace slag.

(x) Materials used as refractory (*e.g.*, alumina, silicon, fire clay, fire brick).

(xi) Plastics (*e.g.*, polyethylene, polypropylene, polyethylene terephthalate, polystyrene, polyvinyl chloride).

(xii) Other waste material that has a volatile solids concentration of 0.5 weight percent (on a dry basis) or less.

(xiii) Other waste material that has a DOC value of 0.3 weight percent (on a wet basis) or less. DOC value must be determined using a 60-day anaerobic biodegradation test procedure identified in §98.464(b)(4)(i).

(d) This source category consists of the following sources at industrial waste landfills: Landfills, gas collection systems at landfills, and destruction devices for landfill gases (including flares).

[75 FR 39773, July 12, 2010, as amended at 76 FR 73907, Nov. 29, 2011, 77 FR 51495, Aug. 24, 2012; 78 FR 71979, Nov. 29, 2013]

§98.461 Reporting threshold.

You must report GHG emissions under this subpart if your facility contains an industrial waste landfill meeting the criteria in §98.460 and the facility meets the requirements of §98.2(a)(2). For the purposes of §98.2(a)(2), the emissions from the industrial waste landfill are to be determined using the methane generation corrected for oxidation as determined using Equation TT–6 of this subpart times the global warming potential for methane in Table A–1 of subpart A of this part.

§98.462 GHGs to report.

(a) You must report CH_4 generation and CH_4 emissions from industrial waste landfills.

(b) You must report CH_4 destruction resulting from landfill gas collection and destruction devices, if present.

(c) You must report under subpart C of this part (General Stationary Fuel Combustion Sources) the emissions of CO_2, CH_4, and N_2O from each stationary combustion unit associated with the landfill gas destruction device, if present, by following the requirements of subpart C of this part.

§98.463 Calculating GHG emissions.

(a) For each industrial waste landfill subject to the reporting requirements of this subpart, calculate annual modeled CH_4 generation according to the applicable requirements in paragraphs (a)(1) through (a)(3) of this section. Apply Equation TT–1 of this section for each waste stream disposed of in the landfill and sum the CH_4 generation rates for all waste streams disposed of in the landfill to calculate the total annual modeled CH_4 generation rate for the landfill.

(1) Calculate annual modeled CH_4 generation using Equation TT–1 of this section.

$$G_{CH4} = \left[\sum_{x=S}^{T-1}\left\{W_x \times DOC_x \times MCF \times DOC_F \times F \times \frac{16}{12} \times \left(e^{-k(T-x-1)} - e^{-k(T-x)}\right)\right\}\right] \quad \text{(Eq. TT-1)}$$

Where:

G_{CH4} = Modeled methane generation in reporting year T (metric tons CH_4).

X = Year in which waste was disposed.

S = Start year of calculation. Use the year 1960 or the opening year of the landfill, whichever is more recent.

T = Reporting year for which emissions are calculated.

W_X = Quantity of waste disposed in the industrial waste landfill in year X from measurement data and/or other company records (metric tons, as received (wet weight)).

DOC_X = Degradable organic carbon for waste disposed in year X from Table TT–1 to this subpart or from measurement data [as specified in paragraph (a)(3) of this section], if available [fraction (metric tons C/metric ton waste)].

DOC_F = Fraction of DOC dissimilated (fraction); use the default value of 0.5. If measured values of DOC are available using the 60-day anaerobic biodegradation test procedure identified in §98.464(b)(4)(i), use a default value of 1.0.

MCF = Methane correction factor (fraction). Use the default value of 1 unless there is active aeration of waste within the landfill during the reporting year. If there is active aeration of waste within the landfill during the reporting year, use either the default value of 1 or select an alternative value no less than 0.5 based on site-specific aeration parameters.

F = Fraction by volume of CH_4 in landfill gas (fraction, dry basis, corrected to 0% oxygen). If you have a gas collection system, use the annual average CH_4 concentration from measurement data for the current reporting year; otherwise, use the default value of 0.5.

k = Decay rate constant from Table TT–1 to this subpart (yr^{-1}). Select the most applicable k value for the majority of the past 10 years (or operating life, whichever is shorter).

(2) *Waste stream quantities.* Determine annual waste quantities as specified in paragraphs (a)(2)(i) through (ii) of this section for each year starting with January 1, 1960 or the year the landfills first accepted waste if after January 1, 1960, up until the most recent reporting year. The choice of method for determining waste quantities will vary according to the availability of historical data. Beginning in the first emissions reporting year (2011 or later) and for each year thereafter, use the procedures in paragraph (a)(2)(i) of this section to determine waste stream quantities. These procedures should also be used for any year prior to the first emissions reporting year for which the data are available. For other historical years, use paragraph (a)(2)(i) of this section, where waste disposal records are available, and use the procedures outlined in paragraph (a)(2)(ii) of this section when waste disposal records are unavailable, to determine waste stream quantities. Historical disposal quantities deposited (*i.e.*, prior to the first year in which monitoring begins) should only be determined once, as part of the first annual report, and the same values should be used for all subsequent annual reports, supplemented by the next year's data on new waste disposal.

(i) Determine the quantity of waste (in metric tons as received, *i.e.*, wet weight) disposed of in the landfill separately for each waste stream by any one or a combination of the following methods.

(A) Direct mass measurements.

(B) Direct volume measurements multiplied by waste stream density determined from periodic density measurement data or process knowledge.

(C) Mass balance procedures, determining the mass of waste as the difference between the mass of the process inputs and the mass of the process outputs.

(D) The number of loads (*e.g.*, trucks) multiplied by the mass of waste per load based on the working capacity of the container or vehicle.

(ii) Determine the historical disposal quantities for landfills using the Waste Disposal Factor approach in paragraphs (a)(2)(ii)(A) and (B) of this section when historical production or processing data are available. If production or processing data are available for a given year, you must use Equation TT–3 of this section for that year. Determine historical disposal quantities using the method specified in paragraph (a)(2)(ii)(C) of this section when historical production or processing data are not available, and for waste streams received from an off-site facility when historical disposal quantities cannot be determined using the methods specified in paragraph (a)(2)(i) of this section.

(A) *Determining Waste Disposal Factor:* For each waste stream disposed of in the landfill, calculate the average waste disposal rate per unit of production or unit throughput using all available waste quantity data and corresponding production or processing rates for the process generating that waste or, if appropriate, the facility, using Equation TT–2 of this section.

$$WDF = \left[\sum_{x=Y_1}^{Y_2} \left\{ \frac{W_x}{N \times P_x} \right\} \right] \qquad \text{(Eq. TT-2)}$$

Where:

WDF = Average waste disposal factor as determined for the first annual report required for this industrial waste landfill (metric tons per production unit).

X = Year in which waste was disposed. Include only those years for which disposal and production data are both available; the years do not need to be sequential.

Y_1 = First year in which disposal and production/throughput data are both available.

Y_2 = First year for which GHG emissions from this industrial waste landfill must be reported.

N = Number of years for which disposal and production/throughput data are both available.

W_x = Quantity of waste placed in the industrial waste landfill in year X from measurement data and/or other company records (metric tons, as received (wet weight)).

P_x = Quantity of product produced or feedstock entering the process or facility in year X from measurement data and/or other company records (production units). You must use the same basis for all years in the calculation. That is, P_x must be determined based on production (quantity of product produced) for all ''N'' years or P_x must be determined based on throughput (quantity of feedstock) for all ''N'' years.

(B) *Calculate waste:* For each waste stream disposed of in the landfill, calculate the waste disposal quantities for historic years in which direct waste disposal measurements are not available using historical production data and Equation TT–3 of this section.

$$W_x = WDF \times P_x \qquad \text{(Eq. TT-3)}$$

Where:

X = Historic year in which waste was disposed.

W_x = Calculated quantity of waste placed in the landfill in year X (metric tons).

WDF = Average waste disposal factor from Equation TT–2 of this section (metric tons per production unit).

P_x = Quantity of product produced or feedstock entering the process or facility in year X from measurement data and/or other company records (production units). You must use the same basis for P_x (either production only or throughput only) as used to determine WDF in Equation TT–2 of this section.

(C) For any year in which historic production or processing data are not available such that historic waste quantities cannot be estimated using Equation TT–3 of this section, calculate an average annual bulk waste disposal quantity using either Equation TT–4a of this section when data are available consecutively for the most recent disposal years or Equation TT–4b of this section when data are available for sporadic (non-consecutive) years.

$$W_x = \frac{LFC}{(YrData - YrOpen + 1)} \qquad \text{(Eq. TT-4a)}$$

Where:

W_X = Quantity of waste placed in the landfill in year X (metric tons, wet basis). This annual bulk waste disposal quantity applies for all years from ''YrOpen'' to ''YrData'' inclusive.

LFC = Capacity of the landfill used (or the total quantity of waste-in-place) at the end of the ''YrData'' from design drawings or engineering estimates (metric tons). For closed landfills for which waste quantity data are not available, use the landfill's design capacity.

YrData = The year prior to the year when waste disposal data are first available for all subsequent years from company records or from Equation TT–3 of this section. For landfills for which waste quantity data are not available, the year in which the landfill last received waste.

YrOpen = Year 1960 or the year in which the landfill first received waste from company records, whichever is more recent. If no data are available for estimating

YrOpen for a closed landfill, use 1960 as the default "YrOpen" for the landfill.

$$W_x = \frac{WIP - \sum_{n-1}^{NYrData} W_{meas,n}}{(YrLast - YrOpen + 1 - NYrData)} \qquad \text{(Eq. TT-4b)}$$

Where:

W_X = Quantity of waste placed in the landfill in year X (metric tons, wet basis). This annual bulk waste disposal quantity applies for all years for which waste quantity data are not available from company records or from Equation TT–3 of this section.

WIP = Quantity of waste in-place at the start of the reporting year from design drawings or engineering estimates (metric tons). For closed landfills for which waste in-place quantities are not available, use the landfill's design capacity.

$W_{meas,n}$ = Annual quantity of waste placed in the landfill for the nth measurement year from company records or from Equation TT–3 of this section.

YrLast = The last year, prior to the reporting year, that the landfill received waste.

YrOpen = Year 1960 or the year in which the landfill first received waste from company records, whichever is more recent. If no data are available for estimating YrOpen for a closed landfill, use 1960 as the default "YrOpen" for the landfill.

NYrData = The number of years for which annual waste disposal quantities are available from company records or from Equation TT–3 of this section from YrOpen to YrLast inclusive.

(3) *Degradable organic content (DOC).* For any year, X, in Equation TT–1 of this section, use either the applicable default DOC values provided in Table TT–1 of this subpart or determine values for DOC_x as specified in paragraphs (a)(3)(i) through (iv) of this section. When developing historical waste quantity data, you may use default DOC values from Table TT–1 of this subpart for certain years and determined values for DOC_x for other years. The historical values for DOC or DOC_x must be developed only for the first annual report required for the industrial waste landfill; and used for all subsequent annual reports (*e.g.*, if DOC for year x=1990 was determined to be 0.15 in the first reporting year, you must use 0.15 for the 1990 DOC value for all subsequent annual reports).

(i) For the first year in which GHG emissions from this industrial waste landfill must be reported, determine the DOC_x value of each waste stream disposed of in the landfill no less frequently than once per quarter using the methods specified in §98.464(b). Calculate annual DOC_x for each waste stream as the arithmetic average of all DOC_x values for that waste stream that were measured during the year.

(ii) For subsequent years (after the first year in which GHG emissions from this industrial waste landfill must be reported), either use the DOC_x of each waste stream calculated for the most recent reporting year for which DOC values were determined according to paragraph (a)(3)(i) of this section, or determine new DOC values for that year following the requirements in paragraph (a)(3)(i) of this section. You must determine new DOC values following the requirements in paragraph (a)(3)(i) of this section if changes in the process operations occurred during the previous reporting year that can reasonably be expected to alter the characteristics of the waste stream, such as the water content or volatile solids concentration. Should changes to the waste stream occur, you must revise the GHG Monitoring Plan as required in §98.3(g)(5)(iii) and report the new DOC_x value according to the requirements of §98.466.

(iii) If DOC_x measurement data for each waste stream are available according to the methods specified in §98.464(b) for years prior to the first year in which GHG emissions from this industrial waste landfill must be reported, determine DOC_x for each waste stream as the arithmetic average of all DOC_x values for that waste stream that were measured in Year X. A single measurement value is acceptable for determining DOC_x for years prior to the first reporting year.

(iv) For historical years for which DOC_x measurement data, determined according to the methods specified in § 98.464(b), are not available, determine the historical values for DOC_x using the applicable methods specified in paragraphs (a)(3)(iv)(A) and (B) of this section. Determine these historical values for DOC_x only for the first annual report required for this industrial waste landfill; historical values for DOC_x calculated for this first annual report should be used for all subsequent annual reports.

(A) For years in which waste stream-specific disposal quantities are determined (as required in paragraphs (a)(2)(ii)(A) and (B) of this section), calculate the average DOC value for a given waste stream as the arithmetic average of all DOC measurements of that waste stream that follow the methods provided in § 98.464(b), including any measurement values for years prior to the first reporting year and the four measurement values required in the first reporting year. Use the resulting waste-specific average DOC value for all applicable years (*i.e.*, years in which waste stream-specific disposal quantities are determined) for which direct DOC measurement data are not available.

(B) For years for which bulk waste disposal quantities are determined according to paragraphs (a)(2)(ii)(C) of this section, calculate the weighted average bulk DOC value according to the following: Calculate the average DOC value for each waste stream as the arithmetic average of all DOC measurements of that waste stream that follows the methods provided in § 98.464(b) (generally, this will include only the DOC values determined in the first year in which GHG emissions from this industrial waste landfill must be reported); calculate the average annual disposal quantity for each waste stream as the arithmetic average of the annual disposal quantities for each year in which waste stream-specific disposal quantities have been determined; and calculate the bulk waste DOC value using Equation TT–5 of this section. Use the bulk waste DOC value as DOC_x for all years for which bulk waste disposal quantities are determined according to paragraphs (a)(2)(ii)(C) of this section.

$$DOC_{bulk} = \frac{\sum_{n=1}^{N} \left(DOC_{ave,n} \times W_{ave,n} \right)}{\sum_{n=1}^{N} W_{ave,n}} \qquad \text{(Eq. TT-5)}$$

Where:

DOC_{bulk} = Degradable organic content value for bulk historical waste placed in the landfill (mass fraction).

N = Number of different waste streams placed in the landfill.

n = Index for waste stream.

$DOC_{ave,n}$ = Average degradable organic content value for waste stream ‘‘n’’ based on available measurement data (mass fraction).

$W_{ave,n}$ = Average annual quantity of waste stream ‘‘n’’ placed in the landfill for years in which waste stream-specific disposal quantities have been determined (metric tons per year, wet basis).

(b) For each landfill, calculate CH_4 generation (adjusted for oxidation in cover materials) and CH_4 emissions (taking into account any CH_4 recovery, if applicable, and oxidation in cover materials) according to the applicable methods in paragraphs (b)(1) through (b)(3) of this section.

(1) For each landfill, calculate CH_4 generation, adjusted for oxidation, from the modeled CH_4 (G_{CH_4} from Equation TT–1 of this section) using Equation TT–6 of this section.

$$MG = G_{CH4} \times (1 - OX) \qquad \text{(Eq. TT-6)}$$

Where:

MG = Methane generation, adjusted for oxidation, from the landfill in the reporting year (metric tons CH_4).

G_{CH_4} = Modeled methane generation rate in reporting year from Equation TT–1 of this section (metric tons CH_4).

OX = Oxidation fraction from Table HH–4 of subpart HH of this part.

(2) For landfills that do not have landfill gas collection systems operating during the reporting year, the CH_4 emissions are equal to the CH_4 generation (MG) calculated in Equation TT–6 of this section.

(3) For landfills with landfill gas collection systems in operation during any portion of the reporting year, perform all of the calculations specified in paragraphs (b)(3)(i) through (iv) of this section.

(i) Calculate the quantity of CH_4 recovered according to the requirements at § 98.343(b).

(ii) Calculate CH_4 emissions using the Equation HH–6 of § 98.343(c)(3)(i), except use G_{CH_4} determined using Equation TT–1 of this section in Equation HH–6 of § 98.343(c)(3)(i).

(iii) Calculate CH_4 generation (MG) from the quantity of CH_4 recovered using Equation HH–7 of § 98.343(c)(3)(ii).

(iv) Calculate CH_4 emissions from the quantity of CH_4 recovered using Equation HH–8 of § 98.343(c)(3)(ii).

[75 FR 39773, July 12, 2010, as amended at 76 FR 73907, Nov. 29, 2011; 78 FR 71979, Nov. 29, 2013]

§ 98.464 Monitoring and QA/QC requirements.

(a) For calendar year 2011 monitoring, the facility may submit a request to the Administrator to use one or more best available monitoring methods as listed in § 98.3(d)(1)(i) through (iv). The request must be submitted no later than October 12, 2010 and must contain the information in § 98.3(d)(2)(ii). To obtain approval, the request must demonstrate to the Administrator's satisfaction that it is not reasonably feasible to acquire, install, and operate a required piece of monitoring equipment by January 1, 2011. The use of best available monitoring methods will not be approved beyond December 31, 2011.

(b) For each waste stream placed in the landfill during the reporting year for which you choose to determine volatile solids concentration and/or a waste stream-specific DOC_X, you must collect and test a representative sample of that waste stream using the methods specified in paragraphs (b)(1) through (b)(4) of this section, as applicable.

(1) Develop and follow a sampling plan to collect a representative sample (in terms of composition and moisture content) of each waste stream placed in the landfill for which testing is elected.

(2) Determine the percent total solids and the percent volatile solids of each sample following Standard Method 2540G ‘‘Total, Fixed, and Volatile Solids in Solid and Semisolid Samples’’ (incorporated by reference; *see* § 98.7).

(3) For the purposes of § 98.460(c)(2)(xii), the volatile solids concentration (weight percent on a dry basis) is the percent volatile solids determined using Standard Method 2540G ‘‘Total, Fixed, and Volatile Solids in Solid and Semisolid Samples’’ (incorporated by reference; see § 98.7).

(4) Determine DOC value of a waste stream by either using at least a 60-day anaerobic biodegradation test as specified in paragraph (b)(4)(i) of this section or by estimating the DOC value based on the total and volatile solids measurements as specified in paragraph (b)(4)(ii) of this section.

(i) Perform an anaerobic biodegradation test and determine the DOC value of a waste stream following the procedures and requirements in paragraphs (b)(4)(i)(A) through (E) of this section.

(A) You may use the procedures published by a consensus-based standards organization to conduct a minimum of a 60-day anaerobic biodegradation test. 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 Society of Mechanical Engineers (ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, *http://www.asme.org*), and the North American Energy Standards Board (NAESB, 801 Travis Street, Suite 1675, Houston, TX 77002, (713) 356–0060, *http://www.api.org*).

(B) Use a minimum of four samples: Two waste stream samples, a control sample using a known substrate (such as ethanol), and a digester sludge blank sample. Each waste stream sample must be appropriately ground to ensure the waste material is fully exposed to the anaerobic digester sludge.

(C) Determine the net mass of carbon degraded in the control sample as the difference in the results of the control sample and the digester sludge blank sample. Determine the net mass of carbon degraded in each waste stream sample as the difference in the results of each waste stream sample and the digester sludge blank sample.

(D) Determine the fraction of carbon degraded in the control sample as the net mass of carbon degraded in the control sample divided by the mass of carbon added via the substrate material in the control sample. If less than 50 percent of the theoretical mass of carbon in the control sample is degraded, the test run is invalid.

(E) Determine the DOC of each waste sample using Equation TT–7 of this section. If the DOC values for the two waste stream samples differ by more than 20 percent, the test run is invalid. The DOC of the waste stream is determined as the average DOC value of the two waste stream samples determined during a valid test.

$$DOC_x = \frac{MCD_{sample,x}}{M_{sample,x}} \qquad \text{(Eq. TT-7)}$$

Where:

DOC_X = Degradable organic content of the waste stream in Year X (weight fraction, wet basis)

$MCD_{sample,x}$ = Mass of carbon degraded in the waste stream sample in Year X as determined in paragraph (b)(4)(i)(C) of this section [milligrams (mg)].

$M_{sample,x}$ = Mass of waste stream sample used in the anaerobic degradation test in Year X (mg, wet basis).

(ii) Calculate the waste stream-specific DOC_X value using Equation TT–8 of this section.

$$DOC_x = F_{DOC} \times \frac{\%\,\text{Volatile Solids}_x}{100\%} \times \frac{\%\,\text{Total Solids}_x}{100\%} \qquad \text{(Eq. TT-8)}$$

Where:

DOC_X = Degradable organic content of waste stream in Year X (weight fraction, wet basis)

F_{DOC} = Fraction of the volatile residue that is degradable organic carbon (weight fraction). Use a default value of 0.6.

% Volatile $Solids_X$ = Percent volatile solids determined using Standard Method 2540G Total, ‘‘Fixed, and Volatile Solids in Solid and Semisolid Samples’’ (incorporated by reference; see § 98.7) for Year X [milligrams (mg) volatile solids per 100 mg dried solids].

% Total $Solids_X$ = Percent total solids determined using Standard Method 2540G ‘‘Total, Fixed, and Volatile Solids in Solid and Semisolid Samples’’ (incorporated by reference; see § 98.7) for Year X (mg dried solids per 100 mg wet waste).

(c) For each waste stream that was historically managed in the landfill for which you choose to determine volatile solids concentration and/or a waste stream-specific DOC_X, you must determine volatile solids concentration or DOC_X of the waste stream as initially placed in the landfill using the methods specified in paragraph (c)(1) or (2) of this section, as applicable.

(1) If you can identify a similar waste stream to the waste stream that was historically managed in the landfill, you must determine the volatile solids

concentration or DOC_X of the similar waste stream using the applicable procedures in paragraphs (b)(1) through (4) of this section.

(2) If you cannot identify a similar waste stream to the waste stream that was historically managed in the landfill, you may determine the volatile solids concentration or DOC_X of the historically managed waste stream using process knowledge. You must document the basis for the volatile solids concentration or DOC_X value as determined through process knowledge.

(d) For landfills with gas collection systems, operate, maintain, and calibrate a gas composition monitor capable of measuring the concentration of CH_4 according to the requirements specified at § 98.344(b).

(e) For landfills with gas collection systems, install, operate, maintain, and calibrate a gas flow meter capable of measuring the volumetric flow rate of the recovered landfill gas according to the requirements specified at § 98.344(c).

(f) For landfills with gas collection systems, all temperature, pressure, and if applicable, moisture content monitors must be calibrated using the procedures and frequencies specified by the manufacturer.

(g) For landfills electing to measure the fraction by volume of CH_4 in landfill gas (F), follow the requirements in paragraphs (g)(1) and (g)(2) of this section.

(1) Use a gas composition monitor capable of measuring the concentration of CH_4 on a dry basis that is properly operated, calibrated, and maintained according to the requirements specified at § 98.344(b). You must either use a gas composition monitor that is also capable of measuring the O_2 concentration correcting for excess (infiltration) air or you must operate, maintain, and calibrate a second monitor capable of measuring the O_2 concentration on a dry basis according to the manufacturer's specifications.

(2) Use Equation TT–9 of this section to correct the measured CH_4 concentration to 0% oxygen. If multiple CH_4 concentration measurements are made during the reporting year, determine F separately for each measurement made during the reporting year, and use the results to determine the arithmetic average value of F for use in Equation TT–1 of this part.

$$F = \left(\frac{C_{CH4}}{100\%}\right) \times \left[20.9_c \Big/ \left(20.9 - \%O_2\right) \right] \qquad \text{(Eq. TT-9)}$$

Where:

F = Fraction by volume of CH_4 in landfill gas (fraction, dry basis, corrected to 0% oxygen).

C_{CH4} = Measured CH_4 concentration in landfill gas (volume %, dry basis).

20.9_c = Defined O_2 correction basis, (volume %, dry basis).

20.9 = O_2 concentration in air (volume %, dry basis).

$\%O_2$ = Measured O_2 concentration in landfill gas (volume %, dry basis).

(h) The facility shall document the procedures used to ensure the accuracy of the estimates of disposal quantities and, if the industrial waste landfill has a gas collection system, gas flow rate, gas composition, temperature, pressure, and moisture content measurements. These procedures include, but are 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.

[75 FR 39773, July 12, 2010, as amended at 76 FR 73908, Nov. 29, 2011; 77 FR 51495, Aug. 24, 2012; 78 FR 71979, Nov. 29, 2013]

§ 98.465 Procedures for estimating missing data.

(a) A complete record of all measured parameters used in the GHG emissions calculations is required. Therefore, whenever a quality-assured value of a required parameter is unavailable (*e.g.*, if a meter 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, in accordance with paragraph (b) of this section.

(b) For industrial waste landfills with gas collection systems, follow the procedures for estimating missing data specified in § 98.345(a) and (b).

§ 98.466 Data reporting requirements.

In addition to the information required by § 98.3(c), each annual report must contain the following information for each landfill.

(a) Report the following general landfill information:

(1) A classification of the landfill as ''open'' (actively received waste in the reporting year) or ''closed'' (no longer receiving waste).

(2) The year in which the landfill first started accepting waste for disposal.

(3) The last year the landfill accepted waste (for open landfills, enter the estimated year of landfill closure).

(4) The capacity (in metric tons) of the landfill.

(5) An indication of whether leachate recirculation is used during the reporting year and its typical frequency of use over the past 10 years (*e.g.*, used several times a year for the past 10 years, used at least once a year for the past 10 years, used occasionally but not every year over the past 10 years, not used).

(b) Report the following waste characterization and modeling information:

(1) The number of waste steams (including ''Other Industrial Solid Waste (not otherwise listed)'' and ''Inerts'') for which Equation TT–1 of this subpart is used to calculate modeled CH_4 generation.

(2) A description of each waste stream (including the types of materials in each waste stream) for which Equation TT–1 of this subpart is used to calculate modeled CH_4 generation.

(3) The fraction of CH_4 in the landfill gas, F, (volume fraction, dry basis, corrected to 0% oxygen) for the reporting year and an indication as to whether this was the default value or a value determined through measurement data.

(4) The methane correction factor (MCF) value used in the calculations. If an MCF value other than the default of 1 is used, provide a description of the aeration system, including aeration blower capacity, the fraction of the landfill containing waste affected by the aeration, the total number of hours during the year the aeration blower was operated, and other factors used as a basis for the selected MCF value.

(5) For each waste stream, the decay rate (k) value used in the calculations.

(c) Report the following historical waste information:

(1) [Reserved]

(2) For each waste stream identified in paragraph (b) of this section, the method(s) for estimating historical waste disposal quantities and the range of years for which each method applies.

(3) For each waste stream identified in paragraph (b) of this section for which Equation TT–2 of this subpart is used, provide:

(i) The total number of years (N) for which disposal and production data are both available.

(ii) The year, the waste disposal quantity and production quantity for each year used in Equation TT–2 of this subpart to calculate the average waste disposal factor (WDF).

(iii) The average waste disposal factor (WDF) calculated for the waste stream.

(4) If Equation TT–4a of this subpart is used, provide:

(i) The value of landfill capacity (LFC).

(ii) YrData.

(iii) YrOpen.

(5) If Equation TT–4b of this subpart is used, provide:

(i) WIP (i.e., the quantity of waste in-place at the start of the reporting year from design drawings or engineering estimates (metric tons) or, for closed landfills for which waste in-place quantities are not available, the landfill's design capacity).

(ii) The cumulative quantity of waste placed in the landfill for the years for which disposal quantities are available from company record or from Equation TT–3 of this part.

(iii) YrLast.

(iv) YrOpen.

(v) NYrData.

(d) For each year of landfilling starting with the ''Start Year'' (S) and each year thereafter up to the current reporting year, report the following information:

(1) The calendar year for which the following data elements apply.

(2) The quantity of waste (W_X) disposed of in the landfill (metric tons, wet weight) for the specified year for each waste stream identified in paragraph (b) of this section.

(3) For each waste stream, the degradable organic carbon (DOC_X) value (mass fraction) for the specified year and an indication as to whether this was the default value from Table TT–1 to this subpart, a measured value using a 60-day anaerobic biodegradation test as specified in § 98.464(b)(4)(i), or a value based on total and volatile solids measurements as specified in § 98.464(b)(4)(ii). If DOC_X was determined by a 60-day anaerobic biodegradation test, specify the test method used.

(e) Report the following information describing the landfill cover material:

(1) The type of cover material used (as either organic cover, clay cover, sand cover, or other soil mixtures).

(2) For each type of cover material used, the surface area (in square meters) at the start of the reporting year for the landfill sections that contain waste and that are associated with the selected cover type.

(f) The modeled annual methane generation (G_{CH4}) for the reporting year (metric tons CH_4) calculated using Equation TT–1 of this subpart.

(g) For landfills without gas collection systems, provide:

(1) The annual methane emissions (*i.e.*, the methane generation (MG), adjusted for oxidation, calculated using Equation TT–6 of this subpart), reported in metric tons CH_4.

(2) An indication of whether passive vents and/or passive flares (vents or flares that are not considered part of the gas collection system as defined in § 98.6) are present at this landfill.

(h) For landfills with gas collection systems, in addition to the reporting requirements in paragraphs (a) through (f) of this section, provide:

(1) The annual methane generation, adjusted for oxidation, calculated using Equation TT–6 of this subpart, reported in metric tons CH_4.

(2) The oxidation factor used in Equation TT–6 of this subpart.

(3) All information required under 40 CFR 98.346(i)(1) through (7) and 40 CFR 98.346(i)(9) through (12).

[75 FR 39773, July 12, 2010, as amended at 76 FR 73909, Nov. 29, 2011; 78 FR 71980, Nov. 29, 2013]

§ 98.467 Records that must be retained.

In addition to the information required by § 98.3(g), you must retain the calibration records for all monitoring equipment, including the method or manufacturer's specification used for calibration, and all measurement data used for the purposes of paragraphs § 98.460(c)(2)(xii) or (xiii) or used to determine waste stream-specific DOC_X values for use in Equation TT–1 of this subpart.

[78 FR 71980, Nov. 29, 2013]

§ 98.468 Definitions.

Except as provided below, all terms used in this subpart have the same meaning given in the CAA and subpart A of this part.

Construction and demolition (C&D) waste landfill means a solid waste disposal facility subject to the requirements of subparts A or B of part 257 of this chapter that receives construction and demolition waste and does not receive hazardous waste (defined in § 261.3 of this chapter) or industrial solid waste (defined in § 258.2 of this chapter) or municipal solid waste (defined in § 98.6 of this part) other than residential lead-based paint waste. A C&D waste landfill typically receives any one or more of the following types of solid wastes: roadwork material, excavated material, demolition waste, construction/renovation waste, and site clearance waste.

Design capacity means the maximum amount of solid waste a landfill can accept. For the purposes of this subpart, for landfills that have a permit, the *design capacity* can be determined in terms of volume or mass in the most recent permit issued by the state, local, or Tribal agency responsible for regulating the landfill, plus any in-place waste not accounted for in the most recent permit. If the owner or operator chooses to convert the design capacity from volume to mass to determine its design capacity, the calculation must include a site-specific density. If the design capacity is within 10 percent of the applicability threshold in § 98.460(a) and there is a change in the production process that can reasonably be expected to change the site-specific waste density, the site-specific waste density must be redetermined and the design capacity must be recalculated based on the new waste density.

Industrial sludge means the residual, semi-solid material left from industrial wastewater treatment processes or wet air pollution control devices (e.g., wet scrubbers). *Industrial sludge* includes underflow material collected in primary or secondary clarifiers, settling basins, or precipitation tanks as well as dredged materials from wastewater tanks or impoundments. *Industrial sludge* also includes the semi-solid materials remaining after these materials are dewatered via a belt process, centrifuge, or similar dewatering process.

Solid waste has the meaning established by the Administrator pursuant to the Solid Waste Disposal Act (42 U.S.C.A. 6901 *et seq.*).

Waste stream means industrial solid waste material that is generated by a specific manufacturing process or client. For wastes generated at the facility that includes the industrial waste landfill, a waste stream is the industrial solid waste material generated by a specific processing unit at that facility. For industrial solid wastes that are received from off-site facilities, a waste stream can be defined as each waste shipment or group of waste shipments received from a single client or group of clients that produce industrial solid wastes with similar waste properties.

[75 FR 39773, July 12, 2010, as amended at 76 FR 73910, Nov. 29, 2011; 78 FR 71980, Nov. 29, 2013]

TABLE TT–1 TO SUBPART TT OF PART 98—DEFAULT DOC AND DECAY RATE VALUES FOR INDUSTRIAL WASTE LANDFILLS

Industry/Waste Type	DOC (weight fraction, wet basis)	k [dry climate[a]] (yr^{-1})	k [moderate climate[a]] (yr^{-1})	k [wet climate[a]] (yr^{-1})
Food Processing (other than industrial sludge)	0.22	0.06	0.12	0.18
Pulp and Paper (other than industrial sludge)	0.20	0.02	0.03	0.04
Wood and Wood Product (other than industrial sludge)	0.43	0.02	0.03	0.04
Construction and Demolition	0.08	0.02	0.03	0.04
Industrial Sludge	0.09	0.02	0.04	0.06
Inert Waste [*i.e.*, wastes listed in § 98.460(c)(2)]	0	0	0	0
Other Industrial Solid Waste (not otherwise listed)	0.20	0.02	0.04	0.06

[a] The applicable climate classification is determined based on the annual rainfall plus the recirculated leachate application rate. Recirculated leachate application rate (in inches/year) is the total volume of leachate recirculated from company records or engineering estimates and applied to the landfill divided by the area of the portion of the landfill containing waste [with appropriate unit conversions].

(1) Dry climate = precipitation plus recirculated leachate less than 20 inches/year

(2) Moderate climate = precipitation plus recirculated leachate from 20 to 40 inches/year (inclusive)

(3) Wet climate = precipitation plus recirculated leachate greater than 40 inches/year

Alternatively, landfills that use leachate recirculation can elect to use the k value for wet climate rather than calculating the recirculated leachate rate.

(1) Dry climate = precipitation plus recirculated leachate less than 20 inches/year.

(2) Moderate climate = precipitation plus recirculated leachate from 20 to 40 inches/year (inclusive).

(3) Wet climate = precipitation plus recirculated leachate greater than 40 inches/year.

[75 FR 39773, July 12, 2010, as amended at 76 FR 73910, Nov. 29, 2011; 78 FR 71981, Nov. 29, 2013]

Subpart UU—Injection of Carbon Dioxide

SOURCE: 75 FR 75086, Dec. 1, 2010, unless otherwise noted.

§98.470 Definition of the source category.

(a) The injection of carbon dioxide (CO_2) source category comprises any well or group of wells that inject a CO_2 stream into the subsurface.

(b) If you report under subpart RR of this part for a well or group of wells, you are not required to report under this subpart for that well or group of wells.

(c) A facility that is subject to this part only because it is subject to subpart UU of this part is not required to report emissions under subpart C of this part or any other subpart listed in §98.2(a)(1) or (a)(2).

§98.471 Reporting threshold.

(a) You must report under this subpart if your facility injects any amount of CO_2 into the subsurface.

(b) For purposes of this subpart, any reference to CO_2 emissions in §98.2(i) shall mean CO_2 received.

§98.472 GHGs to report.

You must report the mass of CO_2 received.

§98.473 Calculating CO_2 received.

(a) You must calculate and report the annual mass of CO_2 received by pipeline using the procedures in paragraphs (a)(1) or (a)(2) of this section and the procedures in paragraph (a)(3) of this section, if applicable.

(1) For a mass flow meter, you must calculate the total annual mass of CO_2 in a CO_2 stream received in metric tons by multiplying the mass flow by the CO_2 concentration in the flow, according to Equation UU–1 of this section. You must collect these data quarterly. Mass flow and concentration data measurements must be made in accordance with §98.474.

$$\mathrm{CO}_{2\mathrm{T,r}} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * C_{CO_{2,p,r}} \qquad \text{(Eq. UU-1)}$$

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly mass flow through a receiving flow meter r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (metric tons).

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

(2) For a volumetric flow meter, you must calculate the total annual mass of CO_2 in a CO_2 stream received in metric tons by multiplying the volumetric flow at standard conditions by the CO_2 concentration in the flow and the density of CO_2 at standard conditions, according to Equation UU–2 of this section. You must collect these data quarterly. Volumetric flow and concentration data measurements must be made in accordance with §98.474.

$$\mathrm{CO}_{2\mathrm{T,r}} = \sum_{p=1}^{4}(Q_{r,p} - S_{r,p}) * D * C_{CO_{2,p,r}} \qquad \text{(Eq. UU-2)}$$

where:

$CO_{2T,r}$ = Net annual mass of CO_2 received through flow meter r (metric tons).

$Q_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r in quarter p at standard conditions (standard cubic meters).

$S_{r,p}$ = Quarterly volumetric flow through a receiving flow meter r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

D = Density of CO_2 at standard conditions (metric tons per standard cubic meter): 0.0018682.

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement in flow for flow meter r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

p = Quarter of the year.

r = Receiving flow meter.

(3) If you receive CO_2 through more than one flow meter, you must sum the mass of all CO_2 received in accordance with the procedure specified in Equation UU–3 of this section.

$$CO_2 = \sum_{r=1}^{R} CO_{2T,r} \quad \text{(Eq. UU-3)}$$

where:

CO_2 = Total net annual mass of CO_2 received (metric tons).

$CO_{2T,r}$ = Net annual mass of CO_2 received (metric tons) as calculated in Equation UU–1 or UU–2 for flow meter r.

r = Receiving flow meter.

(b) You must calculate and report the annual mass of CO_2 received in containers using the procedures specified in either paragraph (b)(1) or (b)(2) of this section.

(1) If you are measuring the mass of contents in a container under the provisions of § 98.474(a)(2)(i), you must calculate the CO_2 received in containers using Equation UU–1 of this section.

where:

$CO_{2T,r}$ = Annual mass of CO_2 received in containers r (metric tons).

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (wt. percent CO_2, expressed as a decimal fraction).

$Q_{r,p}$ = Quarterly mass of contents in containers r in quarter p (metric tons).

$S_{r,p}$ = Quarterly mass of contents in containers r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

p = Quarter of the year.

r = Containers.

(2) If you are measuring the volume of contents in a container under the provisions of § 98.474(a)(2)(ii), you must calculate the CO_2 received in containers using Equation UU–2 of this section.

where:

$CO_{2T,r}$ = Annual mass of CO_2 received in containers r (metric tons).

$C_{CO2,p,r}$ = Quarterly CO_2 concentration measurement of contents in containers r in quarter p (vol. percent CO_2, expressed as a decimal fraction).

$S_{r,p}$ = Quarterly volume of contents in containers r that is redelivered to another facility without being injected into your well in quarter p (standard cubic meters).

$Q_{r,p}$ = Quarterly volume of contents in containers r in quarter p (standard cubic meters).

D = Density of the CO_2 received in containers at standard conditions (metric tons per standard cubic meter): 0.0018682.

p = Quarter of the year.

r = Containers.

[75 FR 75078, Dec. 1, 2010, as amended at 78 FR 71981, Nov. 29, 2013]

§ 98.474 Monitoring and QA/QC requirements.

(a) *CO_2 received.* (1) You must determine the quarterly flow rate of CO_2 received by pipeline by following the most appropriate of the following procedures:

(i) You may measure flow rate at the receiving custody transfer meter prior to any subsequent processing operations at the facility and collect the flow rate quarterly.

(ii) If you took ownership of the CO_2 in a commercial transaction, you may use the quarterly flow rate data from the sales contract if it is a one-time transaction or from invoices or manifests if it is an ongoing commercial transaction with discrete shipments.

(iii) If you inject CO_2 from a production process unit that is part of your facility, you may use the quarterly CO_2 flow rate that was measured at the equivalent of a custody transfer meter following procedures provided in subpart PP of this part. To be the equivalent of a custody transfer meter, a meter must measure the flow of CO_2 being transported to an injection well to the same degree of accuracy as a meter used for commercial transactions.

(2) You must determine the quarterly mass or volume of contents in all containers if you receive CO_2 in containers by the most appropriate of the following procedures:

(i) You may measure the mass of contents of containers summed quarterly using weigh bills, scales, or load cells.

(ii) You may determine the volume of the contents of containers summed quarterly.

(iii) If you took ownership of the CO_2 in a commercial transaction, you may use the quarterly mass or volume of contents from the sales contract if it is a one-time transaction or from invoices or manifests if it is an ongoing commercial transaction with discrete shipments.

(3) You must determine a quarterly concentration of the CO_2 received that is representative of all CO_2 received in that quarter by following the most appropriate of the following procedures:

(i) You may sample the CO_2 stream at least once per quarter at the point of receipt and measure its CO_2 concentration.

(ii) If you took ownership of the CO_2 in a commercial transaction for which the sales contract was contingent on CO_2 concentration, and if the supplier of the CO_2 sampled the CO_2 stream in a quarter and measured its concentration per the sales contract terms, you may use the CO_2 concentration data from the sales contract for that quarter.

(iii) If you inject CO_2 from a production process unit that is part of your facility, you may report the quarterly CO_2 concentration of the CO_2 stream supplied that was measured following procedures provided in subpart PP of this part as the quarterly CO_2 concentration of the CO_2 stream received.

(4) You must assume that the CO_2 you receive meets the definition of a CO_2 stream unless you can trace it through written records to a source other than a CO_2 stream.

(b) *Measurement devices.* (1) All flow meters must be operated continuously except as necessary for maintenance and calibration.

(2) You must calibrate all flow meters used to measure quantities reported in §98.476 according to the calibration and accuracy requirements in §98.3(i).

(3) You must operate all measurement devices according to one of the following. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice. Consensus-based standards organizations include, but are not limited to, the following: ASTM International, the American National Standards Institute (ANSI), the American Gas Association (AGA), the American Society of Mechanical Engineers (ASME), the American Petroleum Institute (API), and the North American Energy Standards Board (NAESB).

(4) You must ensure that any flow meter calibrations performed are National Institute of Standards and Technology (NIST) traceable.

(c) *General.* (1) If you measure the concentration of any CO_2 quantity for reporting, you must measure according to one of the following. You may use an appropriate standard method published by a consensus-based standards organization if such a method exists or an industry standard practice.

(2) You must convert all measured volumes of CO_2 to the following standard industry temperature and pressure conditions for use in Equations UU–2 of this subpart: standard cubic meters at a temperature of 60 degrees Fahrenheit and at an absolute pressure of 1 atmosphere.

(3) For 2011, you may follow the provisions of §98.3(d)(1) through (2) for best available monitoring methods

rather than follow the monitoring requirements of this section. For purposes of this subpart, any reference to the year 2010 in § 98.3(d)(1) through (2) shall mean 2011.

§ 98.475 Procedures for estimating missing data.

A complete record of all measured parameters used in the GHG quantities calculations is required.

(a) Whenever the monitoring procedures for all facilities that used flow meters covered under this subpart cannot be followed to measure flow, the following missing data procedures must be followed:

(1) Another calculation methodology listed in § 98.474(a)(1) must be used if possible.

(2) If another method listed in § 98.474(a)(1) cannot be used, a quarterly flow rate value that is missing must be estimated using a representative flow rate value from the nearest previous time period.

(b) Whenever the monitoring procedures of this subpart cannot be followed to measure quarterly quantity of CO_2 received in containers, the most appropriate of the following missing data procedures must be followed:

(1) Another calculation methodology listed in § 98.474(a)(2) must be used if possible.

(2) If another method listed in § 98.474(a)(2) cannot be used, a quarterly mass or volume that is missing must be estimated using a representative mass or volume from the nearest previous time period.

(c) Whenever the monitoring procedures cannot be followed to measure CO_2 concentration, the following missing data procedures must be followed:

(1) Another calculation methodology listed in § 98.474(a)(3) must be used if possible.

(2) If another method listed in § 98.474(a)(3) cannot be used, a quarterly concentration value that is missing must be estimated using a representative concentration value from the nearest previous time period.

§ 98.476 Data reporting requirements.

If you are subject to this part and report under this subpart, you are not required to report the information in § 98.3(c)(4) for this subpart. In addition to the information required by § 98.3(c)(1) through § 98.3(c)(3) and by § 98.3(c)(5) through § 98.3(c)(9), you must report the information listed in this section.

(a) If you receive CO_2 by pipeline, report the following for each receiving flow meter:

(1) The total net mass of CO_2 received (metric tons) annually.

(2) If a volumetric flow meter is used to receive CO_2:

(i) The volumetric flow through a receiving flow meter at standard conditions (in standard cubic meters) in each quarter.

(ii) The volumetric flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in standard cubic meters) in each quarter.

(iii) The CO_2 concentration in the flow (volume percent CO_2 expressed as a decimal fraction) in each quarter.

(3) If a mass flow meter is used to receive CO_2:

(i) The mass flow through a receiving flow meter (in metric tons) in each quarter.

(ii) The mass flow through a receiving flow meter that is redelivered to another facility without being injected into your well (in metric tons) in each quarter.

(iii) The CO_2 concentration in the flow (weight percent CO_2 expressed as a decimal fraction) in each quarter.

(4) The standard or method used to calculate each value in paragraphs (a)(2) through (a)(3) of this section.

(5) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (a)(2) through (a)(3) of this section.

(6) Whether the flow meter is mass or volumetric.

(b) If you receive CO_2 in containers, report:

(1) The mass (in metric tons) or volume at standard conditions (in standard cubic meters) of contents in containers in each quarter.

(2) The concentration of CO_2 of contents in containers (volume or weight percent CO_2 expressed as a decimal fraction) in each quarter.

(3) The mass (in metric tons) or volume (in standard cubic meters) of contents in containers that is redelivered to another facility without being injected into your well in each quarter.

(4) The net total mass of CO_2 received (in metric tons) annually.

(5) The standard or method used to calculate each value in paragraphs (b)(1), (b)(2), and (b)(3) of this section.

(6) The number of times in the reporting year for which substitute data procedures were used to calculate values reported in paragraphs (b)(1) and (b)(2) of this section.

(c) If you use more than one receiving flow meter, report the net total mass of CO_2 received (metric tons) through all flow meters annually.

(d) The source of the CO_2 received according to the following categories:

(1) CO_2 production wells.

(2) Electric generating unit.

(3) Ethanol plant.

(4) Pulp and paper mill.

(5) Natural gas processing.

(6) Gasification operations.

(7) Other anthropogenic source.

(8) Discontinued enhanced oil and gas recovery project.

(9) Unknown.

(e) Report the following:

(1) Whether the facility received a Research and Development project exemption from reporting under 40 CFR part 98, subpart RR, for this reporting year. If you received an exemption, report the start and end dates of the exemption approved by EPA.

(2) Whether the facility includes a well or group of wells where a CO_2 stream was injected into subsurface geologic formations to enhance the recovery of oil during this reporting year.

(3) Whether the facility includes a well or group of wells where a CO_2 stream was injected into subsurface geologic formations to enhance the recovery of natural gas during this reporting year.

(4) Whether the facility includes a well or group of wells where a CO_2 stream was injected into subsurface geologic formations for acid gas disposal during this reporting year.

(5) Whether the facility includes a well or group of wells where a CO_2 stream was injected for a purpose other than those listed in paragraphs (e)(1) through (4) of this section. If you injected CO_2 for another purpose, report the purpose of the injection.

[75 FR 75078, Dec. 1, 2010, as amended at 78 FR 71981, Nov. 29, 2013]

§98.477 Records that must be retained.

(a) You must follow the record retention requirements specified by §98.3(g). In addition to the records required by §98.3(g), you must retain quarterly records of CO_2 received, including mass flow rate or contents of containers (mass or volumetric) at standard conditions and operating conditions, operating temperature and pressure, and concentration of these streams. You must retain all required records for at least 3 years.

(b) You must complete your monitoring plans, as described in §98.3(g)(5), by April 1 of the year you begin collecting data.

§98.478 Definitions.

Except as provided below, all terms used in this subpart have the same meaning given in the Clean Air Act and subpart A of this part.

CO_2 received means the CO_2 stream that you receive to be injected for the first time into a well on your facility that is covered by this subpart. CO_2 received includes, but is not limited to, a CO_2 stream from a production process unit inside your facility and a CO_2 stream that was injected into a well on another facility, removed from a discontinued enhanced oil or natural gas or other production well, and transferred to your facility.

PART 99 [RESERVED]