

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 98

[EPA-HQ-OAR-2008-0508; FRL-9171-1]

RIN 2060-AQ03

Mandatory Reporting of Greenhouse Gases From Magnesium Production, Underground Coal Mines, Industrial Wastewater Treatment, and Industrial Waste Landfills

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is promulgating a regulation to require monitoring and reporting of greenhouse gas emissions from magnesium production, underground coal mines, industrial wastewater treatment, and industrial waste landfills. This action adds these four source categories to the list of source categories already required to report greenhouse gas emissions. This action requires monitoring and reporting of greenhouse gases for these source categories only for sources with carbon dioxide equivalent emissions above certain threshold levels as described in this regulation. This action does not require control of greenhouse gases.

DATES: The final rule is effective on September 10, 2010. The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of September 10, 2010.

ADDRESSES: EPA established a single docket under Docket ID No. EPA-HQ-OAR-2008-0508 for this action and for the previous action promulgated October 30, 2009 (74 FR 56260). All documents in the docket are listed on the <http://www.regulations.gov> Web site. Although listed in the index, some information is not publicly available, e.g., confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through <http://www.regulations.gov> or in hard copy at EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone

number for the Air Docket is (202) 566-1741.

FOR FURTHER INFORMATION CONTACT: Carole Cook, Climate Change Division, Office of Atmospheric Programs (MC-6207J), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20460; telephone number: (202) 343-9263; fax number: (202) 343-2342; e-mail address: GHGReportingRule@epa.gov. For technical information and implementation materials, please go to the Web site <http://www.epa.gov/climatechange/emissions/ghgrulemaking.html>. To submit a question, select Rule Help Center, followed by Contact Us.

SUPPLEMENTARY INFORMATION:

Regulated Entities. The Administrator determined that this action is subject to the provisions of Clean Air Act (CAA) section 307(d). See CAA section 307(d)(1)(V) (the provisions of section 307(d) apply to "such other actions as the Administrator may determine."). The final rule affects underground coal mines, magnesium production, industrial waste landfills, and industrial wastewater treatment facilities that are direct emitters of greenhouse gases (GHGs). Regulated categories and entities include those listed in Table 1 of this preamble:

TABLE 1—EXAMPLES OF AFFECTED ENTITIES BY CATEGORY

Category	NAICS	Examples of affected facilities	
Magnesium Production	331419	Primary refiners of nonferrous metals by electrolytic methods.	
	331492	Secondary magnesium processing plants.	
Underground Coal Mines	212113	Underground anthracite coal mining operations.	
	212112	Underground bituminous coal mining operations.	
Industrial Waste Landfills	562212	Solid waste landfills.	
	322110	Pulp mills.	
	322121	Paper mills.	
	322122	Newsprint mills.	
	322130	Paperboard mills.	
	311611	Meat processing facilities.	
	311411	Frozen fruit, juice, and vegetable manufacturing facilities.	
	311421	Fruit and vegetable canning facilities.	
	221320	Sewage treatment facilities.	
	Industrial Wastewater Treatment	322110	Pulp mills.
		322121	Paper mills.
		322122	Newsprint mills.
		322130	Paperboard mills.
		311611	Meat processing facilities.
		311411	Frozen fruit, juice, and vegetable manufacturing facilities.
311421		Fruit and vegetable canning facilities.	
325193		Ethanol manufacturing facilities.	
324110		Petroleum refineries.	

Table 1 of this preamble is not intended to be exhaustive, but rather provides a guide for readers regarding facilities likely to be affected by this action. Although Table 1 of this preamble lists the types of facilities that

EPA is now aware could be potentially affected by the reporting requirements, other types of facilities not listed in the table could also be subject to reporting requirements. To determine whether you are affected by this action, you

should carefully examine the applicability criteria found in 40 CFR part 98, subpart A as amended by this action. If you have questions regarding the applicability of this action to a particular facility, consult the person

listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Many facilities affected by this final rule have GHG emissions from other source categories listed in 40 CFR part 98. Table 2 of this preamble has been developed as a guide to help reporters affected by this action identify other

source categories (by subpart) that they may need to (1) consider in their facility applicability determination, and (2) include in their reporting. Table 2 of this preamble identifies the subparts that are likely to be relevant to sources with magnesium production, underground coal mines, industrial

wastewater treatment, and industrial waste landfills. The table should only be seen as a guide. Additional subparts in 40 CFR part 98 may be relevant for a given reporter, while some subparts listed in Table 2 of this preamble may not be relevant to all reporters in these source categories.

TABLE 2—SOURCE CATEGORIES AND RELEVANT SUBPARTS

Source category (and main applicable subpart)	Other Subparts in 40 CFR part 98 recommended for review to determine applicability
Magnesium Production	Subpart C: General Stationary Fuel Combustion.
Underground Coal Mines	Subpart C: General Stationary Fuel Combustion.
Industrial Waste Landfills ^a	Subpart C: General Stationary Fuel Combustion. Subpart Y: Petroleum Refineries. Subpart AA: Pulp and Paper Manufacturing. Subpart II: Industrial Wastewater Treatment.
Industrial Wastewater Treatment	Subpart C: General Stationary Fuel Combustion. Subpart Y: Petroleum Refineries. Subpart AA: Pulp and Paper Manufacturing. Subpart TT: Industrial Waste Landfills.

^a The industrial landfills source category was proposed with municipal solid waste landfills under 40 CFR part 98, subpart HH in the April 10, 2009 proposal (74 FR 16448). However, EPA has since decided to separate landfills into two subparts: subpart HH for municipal solid waste landfills (promulgated October 30, 2009 (74 FR 56374) and subpart TT for industrial waste landfills.

Judicial Review. Under CAA section 307(b)(1), judicial review of this final rule is available only by filing a petition for review in the U.S. Court of Appeals for the District of Columbia Circuit by September 10, 2010. Under CAA section 307(d)(7)(B), only an objection to this final rule that was raised with reasonable specificity during the period for public comment can be raised during judicial review. This section also provides a mechanism for us to convene a proceeding for reconsideration, “[i]f the person raising an objection can demonstrate to EPA that it was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time specified for judicial review) and if such objection is of central relevance to the outcome of this rule.” Any person seeking to make such a demonstration to us should submit a Petition for Reconsideration to the Office of the Administrator, Environmental Protection Agency, Room 3000, Ariel Rios Building, 1200 Pennsylvania Ave., NW., Washington, DC 20004, with a copy to the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section, and the Associate General Counsel for the Air and Radiation Law Office, Office of General Counsel (Mail Code 2344A), Environmental Protection Agency, 1200 Pennsylvania Ave., NW., Washington, DC 20004. Note, under CAA section 307(b)(2), the requirements established by this final rule may not be challenged separately in any civil or criminal

proceedings brought by EPA to enforce these requirements.

Acronyms and Abbreviations. The following acronyms and abbreviations are used in this document.

- ASME American Society of Mechanical Engineers
- ASTM American Society for Testing and Materials
- BAMM Best Available Monitoring Methods
- BOD₅ 5-day biochemical oxygen demand
- CAA Clean Air Act
- CBI confidential business information
- CEMS continuous emission monitoring system(s)
- CERCLA Comprehensive Environmental Response, Compensation, and Liability Act
- cf cubic feet
- CFR Code of Federal Regulations
- CH₄ methane
- CO₂ carbon dioxide
- CO₂e CO₂-equivalent
- COD chemical oxygen demand
- DOC Degradable organic carbon
- EIA economic impact analysis
- EO Executive Order
- EPA U.S. Environmental Protection Agency
- FK 5–1–12 dodecafluoro-2-methylpentan-3-one (or Novec™ 612)
- GHG greenhouse gas
- HCFC–22 chlorodifluoromethane (or CHClF₂)
- HFC–23 trifluoromethane (or CHF₃)
- HFCs hydrofluorocarbons
- HFES hydrofluorinated ethers
- ICR information collection request
- kg kilograms
- MSHA Mine Safety and Health Administration
- MSW municipal solid waste
- N₂O nitrous oxide
- NAICS North American Industry Classification System
- NPDES National Pollution Discharge Elimination System

- NTTAA National Technology Transfer and Advancement Act of 1995
- OMB Office of Management and Budget
- PFCs perfluorocarbons
- QA/QC quality assurance/quality control
- RCRA Resource Conservation and Recovery Act
- RFA Regulatory Flexibility Act
- RIA regulatory impact analysis
- SBREFA Small Business Regulatory Enforcement Fairness Act
- scf standard cubic feet
- scfm standard cubic feet per minute
- SF₆ sulfur hexafluoride
- TSCA Toxic Substances Control Act
- U.S. United States
- UMRA Unfunded Mandates Reform Act of 1995
- VOC volatile organic compound(s)

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I. Background

A. Organization of This Preamble

This preamble consists of five sections. The first section provides a brief history of 40 CFR part 98 and describes the purpose and legal authority for today's action.

The second section of this preamble summarizes the revisions made to the general provisions in 40 CFR part 98, subpart A and outlines the specific requirements for the four new source categories being incorporated into 40 CFR part 98 by this action. It also describes the major changes made to these source categories since proposal and provides a brief summary of significant public comments and EPA's responses on issues specific to each source category.

The third section of this preamble summarizes and provides our rationale for the decisions not to include two source categories as distinct subparts in 40 CFR part 98 and not to include reporting requirements for one additional proposed source category under 40 CFR part 98 at this time.

The fourth section of this preamble provides the summary of the cost impacts, economic impacts, and benefits of the final rule and discusses comments on the regulatory impacts analyses for the four additional source categories.

Finally, the last section discusses the various statutory and executive order requirements applicable to this rulemaking.

B. Background on the Final Rule

Today's action finalizes monitoring and reporting requirements for the following four source categories: magnesium production, underground coal mines, industrial waste landfills,¹ and industrial wastewater treatment. With today's action EPA has decided not to include ethanol production and food processing as distinct subparts. Lastly, EPA has made the final decision not to include any reporting requirements for suppliers of coal at this time.

These source categories were proposed on April 10, 2009 (74 FR 16448) as part of a larger rulemaking effort to establish a GHG reporting program for all sectors of the economy. This rulemaking was initiated by EPA in response to the fiscal year 2008 Consolidated Appropriations Act (Appropriations Act).² This Act authorized funding for EPA to develop and publish a rule “* * *to require mandatory reporting of greenhouse gas emissions above appropriate thresholds in all sectors of the economy of the United States.” An accompanying joint explanatory statement directed EPA to “use its existing authority under the Clean Air Act” to develop a mandatory GHG reporting rule.

EPA proposed 40 CFR part 98 on April 10, 2009 (74 FR 16448) and held two public hearings in April 2009. The public comment period ended on June 9, 2009. The final 40 CFR part 98 was signed by EPA's Administrator on September 22, 2009 and published in the **Federal Register** on October 30, 2009 (74 FR 56260). The October 2009 Final Rule, which became effective on December 29, 2009, included reporting requirements for facilities and suppliers in 31 subparts. The April 2009 proposal, however, included monitoring and reporting requirements for a further eleven source categories that were not finalized in the October 30, 2009 action. This action includes monitoring and reporting requirements for four of the eleven source categories (subpart T—Magnesium Production, subpart FF—

Underground Coal Mines, subpart II—Industrial Wastewater Treatment, and subpart TT—Industrial Waste Landfills) that were proposed but not finalized in the October 30, 2009 action, and amends the general provisions for 40 CFR part 98, subpart A. This action also provides EPA's final decision not to include ethanol production and food processing as distinct subparts in 40 CFR part 98, as well as the final decision not to include suppliers of coal in 40 CFR part 98 at this time.³

During the comment period, EPA received a number of detailed comments on the proposal, including comments specific to the proposed subparts for ethanol production, food processing, underground coal mines, industrial waste landfills, industrial wastewater treatment, and suppliers of coal. EPA decided to delay finalizing the reporting requirements for these source categories to allow for additional time to review public comments, perform additional analysis, and consider modifications and alternatives to the proposed methodologies. Changes made to the proposed requirements and significant comments received during the public comment period for 40 CFR part 98, subparts FF, II, and TT are described in more detail in the discussions of the individual source categories included in Section II of this preamble.

Upon further consideration, EPA decided not to include distinct subparts for ethanol production and food processing in 40 CFR part 98 because these facilities will already be covered under the rule due to their aggregate emissions from all applicable source categories in the rule, such as stationary combustion, industrial wastewater, industrial waste landfills, miscellaneous use of carbonates, and any others that may apply. Moreover, EPA has also decided to not include coal suppliers in 40 CFR part 98 because the vast majority of emissions from combustion of coal in the United States is already covered by the rule through reporting by direct emitters. Further explanation of these decisions is provided in more detail in the discussions of the proposed individual source categories in Section III of this preamble.

Summaries of comments on other aspects of the reporting rule, such as the verification approach and selection of source categories, are included and were

¹ The industrial landfills source category was proposed with municipal solid waste landfills under 40 CFR part 98, subpart HH in the April 10, 2009 proposal (74 FR 16448). However, EPA has since decided to separate landfills into two subparts: subpart HH for municipal solid waste landfills (promulgated October 30, 2009 (74 FR 56374)) and subpart TT for industrial landfills.

² Consolidated Appropriations Act, 2008, Public Law 110–161, 121 Stat. 1844, 2128. Congress reaffirmed interest in a GHG reporting rule, and provided additional funding, in the 2009 and 2010 Appropriations Acts (Consolidated Appropriations Act, 2009, Pub. L. 110–329, 122 Stat. 3574–3716 and Consolidated Appropriations Act, 2010, Pub. L. 111–117, 123 Stat. 3034–3408).

³ The remaining four source categories included in the April 2009 proposal but not included here are being repropounded in Proposed Mandatory Reporting of Greenhouse Gases: Petroleum and Natural Gas Systems (75 FR 18608, April 12, 2010) and Proposed Mandatory Reporting of Greenhouse Gases: Additional Sources of Fluorinate GHGs (75 FR 18652, April 12, 2010).

responded to in the preamble to the October 2009 Final Rule (74 FR 56260, October 30, 2009) and in volumes 1 through 14 of “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments.”

C. Legal Authority

EPA is finalizing 40 CFR part 98, subparts T, FF, II, and TT under the existing CAA authorities provided in CAA section 114. As discussed in detail in Sections I.C and II.Q of the preamble to the 2009 final rule (74 FR 56260, October 30, 2009), CAA section 114(a)(1) provides EPA with broad authority to require emissions sources, persons subject to the CAA, manufacturers of process or control equipment, or persons whom the Administrator believes may have necessary information to monitor and report emissions and provide such other information the Administrator requests for the purposes of carrying out any provision of the CAA. EPA may gather information for a variety of purposes, including for the purpose of assisting in the development of emissions standards under CAA section 111, determining compliance with implementation plans or such standards, or more broadly for “carrying out any provision” of the CAA. Section 103 of the CAA authorizes EPA to establish a national research and development program, including nonregulatory approaches and technologies, for the prevention and control of air pollution, including GHGs. As discussed in the proposal (74 FR 16448, April 10, 2009), among other things, data from magnesium production, underground coal mines, industrial wastewater treatment, and industrial waste landfills will inform decisions about whether and how to use CAA section 111 to establish new source performance standards (NSPS) for these four source categories, including whether there are any additional categories of sources that should be listed under CAA section 111(b). The data collected will also inform EPA’s implementation of CAA section 103(g) regarding improvements in sector based nonregulatory strategies and technologies for preventing or reducing air pollutants.

II. Reporting Requirements for Magnesium Production, Underground Coal Mines, Industrial Wastewater Treatment, and Industrial Waste Landfills

A. Overview

40 CFR part 98 requires reporting of GHG emissions and supply from all sectors of the economy, including fossil

fuel suppliers, industrial gas suppliers, and direct emitters of GHGs. It covers various GHGs, including carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF₆), and other fluorinated compounds (e.g., hydrofluoroethers (HFEs)). The rule requires that source categories subject to the rule monitor and report GHGs in accordance with the methods specified in the individual subparts. For a list of the specific GHGs to be reported and the GHG calculation procedures, monitoring, missing data procedures, recordkeeping, and reporting required by facilities subject to each of the four subparts included in today’s action, see Section II.C through II.F of this preamble.

In order to meet the quality assurance and verification requirements of the rule, EPA is establishing an electronic reporting system to facilitate collection of data under this rule. All facilities that are covered under 40 CFR part 98, including those subject to the reporting requirements in 40 CFR part 98, subparts T, FF, II, and TT will use this data system to submit required data.

B. Summary of Changes to the General Provisions of 40 CFR Part 98

Today’s action amends certain requirements in 40 CFR part 98, subpart A (General Provisions). These amendments are summarized in this section of the preamble and apply only to those subparts included in this action. Other than the changes to format discussed immediately below, none of the amendments change the general provisions applicable to those subparts already incorporated into 40 CFR part 98.

Changes to Format. On March 16, 2010, EPA published both a direct final rule and concurrent proposal (75 FR 12451 and 75 FR 12489) that made minor changes to the format of several sections of the general provisions to accommodate the addition of new subparts in the future in a simple and clear manner. The changes included converting into a tabular format the lists of source categories and supply categories that are affected by the October 2009 final rule. The lists, which were originally embedded in three paragraphs of 40 CFR part 98, subpart A (40 CFR 98.2(a)), were moved to three new tables in 40 CFR part 98, subpart A. Each table also indicated the applicable first reporting year for each source and supply category. For source and supply categories included in the 2009 final rule, the first reporting year remains 2010. As a concurrent

harmonizing change, all references to applicable subparts (e.g., “40 CFR part 98 subparts C through JJ”) were replaced by references to the appropriate source or supply category table. Other changes included updating the language for the schedule for submitting reports and calibrating equipment to recognize that subparts that may be added in the future would have later deadlines. These revisions did not change the requirements for subparts included in the 2009 final rule.

The direct final rule notice also stated the direct final rule would become effective May 17, 2010, unless any adverse comments were received by April 15, 2010. If such comments were received, EPA would withdraw the direct final rule and finalize the proposal at a later date. The Agency received two comments that could be construed as adverse and subsequently withdrew the direct final rule on April 30, 2010 (75 FR 22699).

EPA received two sets of ostensibly adverse comments, however neither addressed any of the specific formatting changes EPA made to the General Provisions in the direct final rule. Rather, the commenters focused on portions of the regulatory text that remained unchanged from the original final rule that was published on October 30, 2009 (74 FR 56260). Both raised concerns with sentences that remained the same as they were in the October 2009 final rule and were not related to the formatting changes proposed on March 16, 2010. Specifically, both commenters objected to the reporting of biogenic emissions required under 40 CFR part 98, section 98.3(C)(4)(i) and (ii). EPA did not actually change that requirement from the October 2009 rule but rather revised the reference in the paragraph from “source categories in subparts C through JJ” to “source categories listed in Table A–3 and Table A–4 of this subpart” to reflect the proposed reformatting from lists of subparts to tables.

One of the commenters also objected to the schedule for reporting described in 98.33(b)(2). Again, EPA did not change that requirement at all. Instead, the Agency inserted the phrase “and becomes subject to the rule in the year that it becomes operational” to the sentence that reads “for a new facility or supplier that begins operation on or after January 1, 2010 and becomes subject to the rule in the year it becomes operational, reporting emissions beginning with the first operating month and ending on December 31 of that year.” That additional phrase makes it clear that reporters must meet the applicability requirements for each

source category before they are subject to any reporting requirements but does not actually amend the schedule for reporting itself.

Finally, one commenter objected to regulatory text in 98.3(i)(1) that requires calibration of flow meters and other devices. This specific requirement also remains unchanged from the 2009 final rule. Similar to the above amendment, EPA revised this paragraph not to change the requirements for sources covered by the October 2009 final rule, but rather to allow facilities that must report under any additional subparts to conduct any initial calibrations that are required by the newly published subparts during the first year that the subpart applies rather than in the year 2010. To do that, EPA changed the following sentence, “for facilities and suppliers that become subject to this part about April 1, 2010, the initial calibration shall be conducted on the date that data collection is required to begin” to “for facilities and suppliers that are subject to this part on January 1, 2010, the initial calibration shall be conducted by April 1, 2010. For facilities and suppliers that become subject to this part after April 1, 2010, the initial calibration shall be conducted by the date that data collection is required to begin.”

In both cases, the comments received did not address any of the changes EPA proposed to make to the General Provisions. As a result, EPA is finalizing those proposed minor amendments to accommodate the addition of new subparts in this rulemaking. The additional changes to 40 CFR part 98, subpart A discussed below reflect these changes (*i.e.*, revising Tables A–3 and A–4 instead of 40 CFR 98.2(a)(1), (2) or (4)). As explained above, the comments that could be construed as adverse related to parts of the regulatory text that remained unchanged from the 2009 final rule. If and when EPA decides to make any changes to any regulatory requirements set forth in the October 2009 final rule, including those highlighted in the comments above, the Agency will initiate a separate notice and comment process.

Changes to Applicability. Facilities containing magnesium production, industrial waste landfills, and/or industrial wastewater treatment, are subject to 40 CFR part 98 if they emit 25,000 metric tons CO₂-equivalent (CO₂e) or more per year in combined emissions from combustion units, miscellaneous uses of carbonate, ferroalloy production, glass production, hydrogen production, iron and steel production, lead production, pulp and paper manufacturing, zinc production,

magnesium production, industrial wastewater treatment, and industrial waste landfills, or if they are required to report under 98.2(a)(1). In today’s action, EPA is making revisions to Table A–4 in 40 CFR part 98, subpart A from that included in the direct final rule and accompanying proposal to include the source categories: Magnesium production, industrial wastewater treatment, and industrial waste landfills.

Underground coal mines that are subject to quarterly (or more frequent) sampling of ventilation systems by the Mine Safety and Health Administration (MSHA) are subject to 40 CFR part 98 regardless of the actual facility emissions. In today’s action, we are making revisions to Table A–3 from that included in the direct final rule and accompanying proposal to include the underground coal mine source category.

Changes to the Reporting Schedule. Facilities with existing magnesium production, underground coal mines, industrial wastewater treatment, and industrial waste landfills must begin monitoring GHG emissions on January 1, 2011 in accordance with the methods specified in 40 CFR part 98, subparts T, FF, II, and TT. Facilities must report the GHG emissions and associated verification data required under each of these subparts by March 31, 2012. Facilities with existing reporting requirements for the year 2010 are not required to collect the data required under 40 CFR part 98, subparts T, FF, II, and TT for the reporting year 2010 or report it in 2011.

EPA decided to require reporting of calendar year 2011 emissions for the four source categories finalized in today’s action because the data are crucial to the timely development of future GHG policy and regulatory programs. In the fiscal year 2008 Appropriations Act, Congress requested that EPA develop this reporting program on an expedited schedule, and Congressional inquiries along with public comments reinforce that data collection for calendar year 2011 is a priority. Delaying data collection until calendar year 2012 would mean the data would not be received until 2013, which would likely be too late for many ongoing GHG policy and program development needs.

EPA received a number of comments on the April 2009 proposal from stakeholders expressing concerns that there would be insufficient time between the publication of a final rule and the date on which monitoring must begin. EPA concluded that the time period between the publication of this final action and the January 1, 2011

deadline for beginning monitoring for 40 CFR part 98, subparts T, FF, II, and TT is sufficient to allow facilities to implement the required monitoring methods, including calibrating and installing monitoring equipment. The monitoring requirements for each subpart included in today’s action have not changed significantly from those requirements proposed in April 2009. Although facilities in some source categories will have to make emissions assessments to determine whether their facility exceeds the 25,000 metric tons CO₂e applicability threshold, EPA has concluded that there is ample time to complete this assessment. Many facilities affected by today’s action will not need additional time to make emissions assessments because they will already be subject to monitoring and reporting emissions under other applicable subparts in 40 CFR part 98. For example, pulp and paper mills which may be required to report under 40 CFR part 98, subparts TT and II, are already required to report under 40 CFR part 98, subpart AA and any other applicable source categories if their emissions are more than 25,000 metric tons CO₂e per year. Furthermore, many of those facilities that are not subject to monitoring in 2010 will have already completed some assessments of their emissions from source categories included in the October 2009 Final Rule. For example, many industrial facilities will have already assessed their GHG emissions from combustion units for the 2010 reporting year. For these reasons, EPA concluded that the January 1, 2011 deadline should provide sufficient time for facilities to comply with the rule.

Best Available Monitoring Methods. In the October 2009 Final Rule, facilities had the option to use Best Available Monitoring Methods (BAMM) for the first quarter of the first reporting year. While facilities in the source categories included in today’s action will not automatically be allowed to use BAMM for the first quarter of monitoring (January 1, 2011 to March 31, 2011), facilities will have the option to request the use of BAMM. The request must be submitted by October 12, 2010 and must contain the information specified in 40 CFR 98.3(d)(2)(ii). Specific information regarding the use of BAMM is included in the Monitoring and QA/QC Requirements section of each subpart for the source categories included in today’s action. The use of BAMM for these source categories will not be approved beyond December 31, 2011. The only change to the general provisions, by virtue of inclusion of BAMM in each subpart, is to make it

clear that the automatic three month provision of 98.3 does not apply to these subparts.

For most facilities covered by the source categories in today's action, there are monitoring requirements that may not be typical operating procedure and therefore, monitoring equipment will need to be purchased and installed. In addition, per EPA's experience with the source categories finalized in 2009 final rule, there will likely be facilities with unique circumstances that will require some additional time to comply with the rule requirements. Therefore, EPA decided to allow facilities to request the use of BMM for the first reporting year so that those that are not able to acquire, install, and calibrate the required monitoring equipment due to their unique circumstances may still comply with the rule.

Other Changes to 40 CFR part 98, subpart A. In today's action, we are also amending 40 CFR 98.6 (definitions) to add definitions for several terms used in 40 CFR part 98, subparts T, FF, II, and TT and to clarify the meaning of certain existing terms for purposes of 40 CFR part 98, subpart II.

We are also amending 40 CFR 98.7 (incorporation by reference) to include standard methods references in 40 CFR part 98, subparts FF, II, and TT.

C. Magnesium Production (40 CFR Part 98, Subpart T)

1. Summary of the Final Rule

Source Category Definition. Magnesium production and processing facilities are defined as any facility where magnesium metal is produced through smelting (including electrolytic smelting), refining, or remelting operations, or any site where molten magnesium is used in alloying, casting, drawing, extruding, forming, or rolling operations.

Facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2(a)) summarized in Section II.B of this preamble must report GHG emissions.

GHGs to Report. Each magnesium production facility must report total emissions at the facility level for each of the following gases in metric tons of gas per year resulting from their use as cover gases or carrier gases in magnesium production or processing:

- SF₆.
- HFC-134a.
- FK 5-1-12.
- CO₂.
- Any other GHG as defined in 40 CFR part 98, subpart A (General Provisions) of the rule.

In addition, each facility must report GHG emissions for other source

categories for which calculation methods are provided in the rule. For example, facilities must report CO₂, N₂O, and CH₄ emissions from each stationary combustion unit on site by following the requirements of 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

GHG Emissions Calculation and Monitoring. Owners or operators of magnesium production facilities must calculate emissions of each gas by monitoring the annual consumption of cover gases and carrier gases using one of three methods:

- Use a mass-balance approach that takes into account the following:
 - *Decrease in Inventory:* The decrease in inventory of cover or carrier gases stored in containers from the beginning to the end of the year.
 - *Acquisitions:* The amount of cover or carrier gas acquired through purchases or other transactions.
 - *Disbursements:* The amount of cover or carrier gases disbursed to sources and locations outside the facility through sales or other transactions.
- Monitor the changes in the mass of individual containers as the gases are used.
- Monitor the mass flow of pure cover gas and carrier gas into the cover gas distribution system.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)), reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart T.

Recordkeeping. In addition to the information required by the General Provisions (40 CFR 98.3(g)), reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart T.

2. Summary of Major Changes Since Proposal

No major changes since proposal have been made to the magnesium production sector.

3. Summary of Comments and Responses

No comments specific to regulation of the magnesium production sector were received.

D. Underground Coal Mines (40 CFR Part 98, Subpart FF)

1. Summary of the Final Rule

Source Category Definition. 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 a subsurface coal seam, where the coal is then mined with equipment such as cutting machines, and transported to the surface. Active underground coal mines are underground mines categorized by the MSHA as active and where coal is currently being produced or has been produced within the previous 90 days. This source category includes each ventilation well or shaft, and each degasification system well or shaft, and includes degasification systems deployed before, during, or after mining operations are conducted in a mine area.

This source category does not include abandoned (closed) mines, surface coal mines, post-coal mining activities (e.g., storage or transportation of coal), or coalbed methane recovery from coal seams not associated with active underground coal mines.

Reporters must submit annual GHG reports for facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2(a)(1)) summarized in Section II.B of this preamble.

GHGs to Report. For underground coal mines, report the following:

- Quarterly CH₄ liberation from ventilation and degasification systems.
- Quarterly CH₄ destruction for ventilation and degasification systems and resultant CO₂ emissions, if destruction takes place on-site.

In addition, each facility must report GHG emissions for other source categories for which calculation methods are provided in the rule. For example, facilities must report CO₂, N₂O, and CH₄ emissions from each stationary combustion unit on site by following the requirements of 40 CFR part 98, subpart C (General Stationary Fuel Combustion Sources).

GHG Emissions Calculation and Monitoring. For CH₄ liberated from mine ventilation air, facilities are to monitor CH₄ using either quarterly or more frequent sampling of CH₄ content and gas flow, or continuous emissions monitoring systems (CEMS).

For the quarterly sampling option, coal mine operators are required to either: (a) To obtain the results of the quarterly, or more frequent, testing that MSHA conducts, and use the results to calculate quarterly emissions, or (b) independently collect quarterly, or more frequent, samples of CH₄ released from the ventilation system(s), using MSHA procedures, have these samples analyzed for CH₄ composition, and use

the results to calculate quarterly emissions.

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.

For CH₄ liberated from degasification systems, facilities are to monitor CH₄ using either weekly sampling, or CEMS.

The option of collecting weekly samples includes both measurement of the total gas volume liberated (including that which is emitted or sold, used onsite, or otherwise destroyed (including by flaring)), along with measurements of CH₄ concentrations in gas volumes recovered or emitted. Under this option, facilities must determine weekly gas flow rates and CH₄ composition from these degasification wells and shafts, either on an individual well or shaft basis, or in aggregate at one or more centralized collection points. Methane composition could be determined either by submitting samples to a lab for analysis, or from the use of methanometers at the degasification well site(s) and/or one or more centralized collection point(s).

For the CEMS option, facilities must monitor either individual wellbores, or can monitor gas at points of aggregation, as long as emissions from all wells are addressed, and the methodology for calculating total emissions from all wells is documented.

For all systems with CH₄ destruction, CH₄ destruction is monitored through direct measurement of CH₄ flow to combustion devices with continuous monitoring systems. The resulting CO₂ emissions for onsite combustion devices without energy recovery (*i.e.*, flaring) are to be calculated from these monitored values.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)), reporters must submit additional data that are used to calculate GHG emissions. A list of specific data to be reported for this source category is contained in 40 CFR part 98, subpart FF.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)), reporters must keep records of additional data that are used to calculate GHG emissions. A list of specific records that must be retained for this source category is contained in 40 CFR part 98, subpart FF.

2. Summary of Major Changes Since Proposal

The major changes in this rule since the original proposal are identified in

the following list. The rationale for these and any other significant changes to 40 CFR part 98, subpart FF can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart FF: Underground Coal Mines."

- An option of using one or more CEMS to obtain data on mine ventilation systems was added.
- For CH₄ liberated from degasification systems, the requirement to monitor each well was removed. CEMS may be used to monitor aggregate CH₄ from more than one well, as long as CH₄ from all wells is monitored, and the methodology for estimating total emissions from all wells is documented.
- The requirement for continuous monitoring for total CH₄ liberation at degasification systems was removed. Degasification wells may be monitored with CEMS or through weekly sampling of all degasification wells, including gob gas vent holes and other degasification wells.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. EPA received many comments on this subpart covering numerous topics. EPA's responses to these significant comments can be found in the comment response document for underground coal mines in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart FF: Underground Coal Mines."

Definition of Source Category

Comment: Several commenters stated that many operators currently recover liberated CH₄ for various purposes, including destruction, and therefore CH₄ that has been recovered is no longer an emission as it is not vented into the atmosphere. The commenters recommended that EPA not include recovered CH₄ in the reporting requirements.

Response: EPA agrees that CH₄ that has been recovered and combusted is not emitted. However, EPA does not agree with the commenter that recovered CH₄ should be excluded from the reporting requirements. Recovery projects at mines greatly reduce CH₄ emissions from this source. It is vital that EPA obtain the best information available about these practices for future policy analysis. In addition, since mines with CH₄ collection systems generally monitor the amount of CH₄ collected in these systems, this can provide an effective internal validation method for assessment of CH₄ generation within the mine. As such, data for mines with gas

collection systems are also vitally important to better understand and improve estimates of CH₄ emissions from mines in general. EPA has taken the same approach for the reporting of recovered CH₄ from landfills under 40 CFR part 98, subpart HH.

Comment: Commenters suggested that EPA include abandoned mines in the source category definition. For existing abandoned mines whose operators can be identified from State or Federal records, they recommended that EPA require the installation of appropriate monitoring equipment. They also recommended that EPA make clear that the abandoned mine exception does not apply prospectively.

Response: For currently abandoned mines, EPA considered this emission source and determined that measuring and/or monitoring emissions from abandoned mines would be difficult at this time, since there are currently no robust facility-level monitoring methods available to measure fugitive emissions from abandoned mines. Further, in many cases, EPA concluded that it would be difficult to identify owners of abandoned mine sites, *i.e.*, it would be difficult to identify the responsible parties to monitor and report. Finally, even where the site owner is known, these sites are often unmanned, remote, and lack a source of nearby power, making it burdensome to monitor emissions. EPA may reconsider including abandoned mines in this rule should additional information become available demonstrating that monitoring is feasible.

With regard to the "once in, always in" provision of the proposed reporting rule, a mine covered by the rule that later ceases coal production would need to continue reporting until its emissions fell below the levels specified in the provisions to cease reporting in 40 CFR part 98, subpart A. Mines continue to emit CH₄ after mining activities have ceased and therefore it is prudent to continue monitoring emissions until they are below the threshold.

Comment: For surface mines, while commenters recognized that existing monitoring methods presently may not be robust, some commenters consider the use of existing methods to be preferable to excluding this source of emissions. They suggested that EPA consider requiring these methods for surface mines, adjusting emissions figures appropriately to account for uncertainty.

Response: EPA determined that monitoring emissions from surface mines would be challenging, since there are currently no robust facility-level monitoring methods to measure fugitive

CH₄ emissions from surface mines at this time. Measuring fugitive emissions at specific locations would not adequately capture the emissions from the entire mine, would be expensive and resource-intensive, and difficult for mine operators to implement on a periodic basis. EPA may reconsider including surface mines in this rule should additional information become available demonstrating that monitoring is feasible.

Comment: One commenter expressed concern that even the most accurate instrumentation will have accuracy difficulties based upon varying conditions, calling into question the accuracy of the measurements. Because of this, they recommended that degasification wells be exempt from the rule.

Response: EPA does not agree with the commenter that CH₄ degasification wells should be exempt. While the factors mentioned in the comment may indeed influence the accuracy of measurement of CH₄ from degasification wells, EPA considered this issue when including this source category, and determined that the collection of facility-level data at these mines is still of value to EPA because it provides valuable information for characterizing CH₄ emissions from underground coal mining options. This information is also of value to mine owners, because those facilities reporting under the rule will have stringent monitoring systems in place that will allow them to quantify the mitigation value of destroying CH₄ from their degasification systems.

Reporting Threshold

Comment: One commenter recommended that establishing the reporting threshold at a level of 100,000 metric tons CO₂e/yr instead of the proposed threshold of MSHA quarterly reporting would ensure accurate reporting while sparing small mines and manufacturers from the burdens of compliance.

Response: In developing the threshold for active underground coal mines, EPA considered various emissions-based thresholds, and determined that reporting should be required for those coal mines for which CH₄ emissions from the ventilation system are sampled quarterly by MSHA. MSHA conducts quarterly testing of CH₄ concentration and flow at mines emitting more than 100,000 cubic feet of CH₄ per day. This threshold was selected because subjecting underground mine operators to a new emissions-based threshold would be unnecessarily burdensome and perhaps confusing, since these mines are already subject to MSHA

regulations and therefore would be able to comply with this rule without having to separately determine applicability.

Selection of Proposed GHG Emissions Calculation and Monitoring Methods

Comment: Several commenters recommended that CEMS should be allowed as a monitoring method, but not required, for both ventilation and degasification systems. In particular, they claim that continuous monitoring of CH₄ emissions and air flow rates for all degasification wells and degasification vent holes is not feasible for several reasons. The remote location, unavailability of power, inaccessibility, susceptibility to vandalism, and the relatively short longevity of many degasification and vent holes renders continuous monitoring impractical in many cases.

One commenter generally agreed with EPA's approach to underground coal mine CH₄ monitoring, but urged EPA to require the use of CEMS for ventilation systems in addition to degasification systems.

Most commenters stated that the procedures and quarterly sampling are sufficient as an option for GHG emissions reporting from ventilation of underground coal mines if such data can be received from MSHA. However, some expressed concern that MSHA does not normally report such data back to mines unless requested.

Response: For monitoring CH₄ liberation from underground coal mines, EPA considered several approaches: Engineering approaches whereby default emission factors would be applied to total annual coal production; periodic sampling of CH₄; daily sampling of CH₄; and the use of CEMS. EPA selected periodic sampling as its minimum requirement because the cost burden of purchasing, installing and maintaining CEMS, and the cost of maintaining a more frequent sampling program were not justifiable under present circumstances relative to the greater measurement accuracy achieved.

We agree that CEMS should be allowed, but not required, to monitor CH₄ liberation from ventilation and degasification systems, and have changed the rule accordingly. For systems where recovered CH₄ is sold, destroyed, or used on site, EPA determined that such systems are already installed on most wells, and CEMS are required.

For monitoring at ventilation systems, EPA has concluded that quarterly sampling is sufficient as an option for GHG monitoring from ventilation systems. Quarterly sampling was chosen for ventilation systems because that is

the frequency of sampling conducted by MSHA. Greater frequency would provide more accurate data; however, the increased burden would outweigh the benefits of improved accuracy for the purposes of this reporting rule at this time. The quarterly option represents a balance between burden on reporters and accuracy of data.

EPA is aware that MSHA does not normally report sampling data back to mines unless requested. However, since MSHA is conducting sampling that provides data useful to this rule, EPA determined that it should include use of the data collected by MSHA, by facilities that do obtain this data from MSHA, as an option under this rule. Under this option, facilities would input MSHA data into the emissions calculations required under this rule. Mines that do not obtain this data from MSHA must conduct sampling as specified in the rule.

EPA added the use of CEMS at ventilation systems as an option for monitoring. CEMS are not currently widely implemented at ventilation systems, but mines evaluating the feasibility of mitigation, abatement, or use of ventilation air methane might install CEMS to monitor methane, and this monitoring would be allowed under this rule.

For monitoring at degasification systems, it was determined that weekly sampling is sufficient. Most degasification systems conduct continuous monitoring and where this type of monitoring is already in place, it should be used for purposes of this rule. Based on interviews with a number of mine operators, for many of those sites where continuous monitoring is not being conducted (primarily for gob gas vent holes) degasification wells are monitored at least weekly. Moreover, EPA determined that emissions do not generally vary much from week to week for mine degasification systems, so the weekly measurements would provide sufficient accuracy.

Cost Data

Comment: Many commenters noted that EPA did not appropriately take into consideration the full costs of compliance associated with the proposed rule, particularly those associated with the installation of CEMS on all degasification wells and vent holes. They noted that both the number of impacted wells and vent holes, as well as the costs associated with implementing such systems, was probably underestimated.

Response: Based on these comments and further analysis, EPA reevaluated its cost assessment, revised its costs,

and on the basis of those revised costs, modified the monitoring requirements.

EPA reassessed the number of degasification wells and vent holes that would likely be associated with mines required to report under the rule. This resulted in a substantially larger estimate of the number of degasification wells that would be required to install CEMS systems in compliance with the originally proposed requirements, with an associated greater incremental cost burden.

EPA determined that implementing CEMS on some degasification wells could be quite costly, and in many cases, would be difficult and/or impractical due to remote location, unavailability of power, inaccessibility, susceptibility to vandalism, and the relatively short longevity of many degasification and vent holes. As a result, EPA included consideration of the costs associated with weekly or more frequent sampling, as an alternative to the installation of CEMS, to address this potential burden. For more detailed information on costs, please see Section 4 of the Economic Impact Analysis (EIA) found in docket EPA-OAR-2008-0508.

E. Industrial Wastewater Treatment (40 CFR Part 98, Subpart II)

1. Summary of the Final Rule

Source Category Definition. This source category applies to anaerobic processes used to treat industrial wastewater and wastewater treatment sludge only at pulp and paper mills, food processing facilities, ethanol production facilities, and petroleum refineries. It does not include anaerobic processes used to treat wastewater and wastewater treatment sludge at other industrial facilities. It does not include municipal wastewater treatment plants or separate treatment of sanitary wastewater at industrial facilities. It does not include oil/water separators. This source category consists of the following: Anaerobic reactors, anaerobic lagoons, anaerobic sludge digesters, and biogas destruction devices.

Facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2(a)) summarized in Section II.B of this preamble must report GHG emissions.

GHGs To Report. Operators of anaerobic processes used to treat industrial wastewater and industrial wastewater treatment sludge at the above noted facilities must report the following:

- The amount of CH₄ generated, recovered, and emitted from treatment

of industrial wastewater using anaerobic lagoons or anaerobic reactors.

- The amount of CH₄ recovered and emitted from anaerobic sludge digesters.

- The amount of CH₄ destroyed by and emitted from biogas collection systems and destruction devices.

Operators of anaerobic wastewater treatment sludge digesters are not required to report the amount of CH₄ generated. It is EPA's understanding that all anaerobic sludge digesters are designed for CH₄ recovery and are therefore not expected to emit CH₄ directly from the digester apparatus. Further, this rule requires operators of anaerobic sludge digesters to report the amount of CH₄ recovered and emitted from the recovery system. Therefore, all CH₄ that is generated in the anaerobic sludge digester is already accounted for in the amount of CH₄ recovered and emitted from the recovery system. For this reason, a separate calculation and report of the amount of CH₄ generated is not necessary.

GHG Emissions Calculation and Monitoring. For each anaerobic wastewater treatment process, facilities must calculate the mass of CH₄ generated using the following inputs and data:

- Volume of wastewater sent to an anaerobic treatment process.

- Average concentration of chemical oxygen demand (COD) or 5-day biochemical oxygen demand (BOD₅) of wastewater entering an anaerobic treatment process.

- Maximum CH₄ producing potential of wastewater (0.25 for COD, 0.6 for BOD₅).

- CH₄ conversion factor for the type of wastewater treatment process used.

For each anaerobic process (such as a reactor, lagoon, or sludge digester) from which biogas is recovered, covered facilities must calculate the mass of CH₄ recovered using the following inputs and data:

- Cumulative volumetric flow of biogas for the monitoring period.

- Average CH₄ content of the biogas.

- Temperature, pressure, and moisture content at which flow is measured, as needed to accurately calculate biogas flow and CH₄ content.

For each anaerobic process (such as reactor, lagoon, or sludge digester) from which biogas is recovered, covered facilities must calculate the mass of CH₄ emitted using the following inputs and data:

- Mass of CH₄ recovered.

- Collection efficiency for the anaerobic process, based on the type of anaerobic process.

- Destruction efficiency of the biogas collection and combustion system.

- Fraction of hours the destruction device was operating in the reporting year.

Data Reporting. In addition to the information required to be reported by the General Provisions (40 CFR 98.3(c)), facilities must submit additional data that are used to calculate or verify GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart II.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)) facilities must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart II.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified below. The rationale for these and any other significant changes can be found below or in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart II: Industrial Wastewater Treatment," and "Technical Support Document for Industrial Wastewater Treatment."

- The source category has been renamed Industrial Wastewater Treatment and the applicability of this subpart has been clarified. Only petroleum refineries, and ethanol production, food processing, and pulp and paper facilities that meet the requirements of 98.2(a)(2) are required to report CH₄ emissions from anaerobic processes used to treat industrial wastewater and industrial wastewater treatment sludge and biogas destruction devices. Separate treatment of sanitary wastewater at industrial facilities is not included in the applicability, nor are facilities that do not employ the wastewater treatment processes listed in the source definition (*i.e.*, those that employ only aerobic or anoxic processes are not required to report).

- The requirement to report emissions from oil/water separators at petroleum refineries has been removed. EPA expects no direct emissions of CO₂ or other GHG from these oil/water separators.

- Because petrochemical facilities are not known to employ anaerobic wastewater treatment, this sector has been removed from the final version of the rule.

- For ease of reporting, EPA revised the regulation to allow for either continuous or weekly monitoring of biogas CH₄ concentration. Facilities may use either installed or portable monitors to measure the CH₄ concentration. Further, EPA added BOD₅ as an

alternative to measuring COD to determine the organic load of influent to anaerobic wastewater treatment systems.

3. Summary of Comments and Response

This section contains a brief summary of major comments and responses. EPA received many comments on this subpart covering numerous topics. EPA's responses to these comments can be found in the comment response document for industrial wastewater treatment in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart II: Industrial Wastewater Treatment."

Comment: Many commenters expressed confusion about which facilities were required to report emissions from wastewater treatment systems. Some commenters requested EPA clarify the definitions of aerobic and anaerobic wastewater treatment, while others were uncertain whether only the industries explicitly mentioned in the rule were required to report. Many commenters also requested that EPA clarify whether the rule applied to centralized municipal wastewater treatment plants and treatment of sanitary wastewater at industrial facilities.

Response: EPA revised 40 CFR 98.351 to clarify that only ethanol production, food processing, petroleum refining, and pulp and paper manufacturing facilities must report wastewater treatment system emissions if they both meet the requirements of 40 CFR 98.2 (a)(1) or (2) and operate an anaerobic process to treat industrial wastewater or industrial wastewater treatment sludge.

With regard to anaerobic processes covered by the rule, EPA revised 40 CFR 98.350 to state explicitly that facilities are only required to report emissions for the following: anaerobic reactors, anaerobic lagoons, anaerobic sludge digesters, and biogas destruction devices. To further clarify the scope of 40 CFR part 98, subpart II, EPA has removed emission factors for aerobic processes used to treat industrial wastewater from Table II-1 of 40 CFR part 98, subpart II because these processes are not covered by the reporting rule.

EPA agrees with commenters that it is appropriate to exclude centralized domestic or municipal wastewater treatment plants from 40 CFR part 98, as was the case in the proposed rule. EPA continues to exclude municipal wastewater treatment plants from the final rule, and has retitled 40 CFR part 98, subpart II as Industrial Wastewater Treatment to clarify the applicability of this subpart.

EPA also agrees with commenters that it is appropriate to exclude separate treatment of sanitary wastewater at industrial facilities from 40 CFR part 98. Most such sanitary treatment plants are much smaller than municipal wastewater treatment plants and few use anaerobic treatment. As a result, EPA explicitly excluded these systems from 40 CFR part 98; however, anaerobic processes used to treat combined industrial and sanitary wastewater are covered by the rule.

Comment: Multiple commenters objected to the inclusion of emissions from petroleum refinery oil/water separators in the rule. Some argued that the GHG emissions from these devices would be insignificant. Others asserted that the GHG emissions calculations were unsupported and that this subpart was the only one to consider the atmospheric conversion of volatile organic compounds (VOCs) to CO₂ in the calculation of GHG emissions.

Response: In the proposed rule, EPA included a method to calculate CO₂ emissions that indirectly come from VOCs from petroleum refinery oil/water separators. EPA agrees with commenters that this requirement should be removed because this is the only source category to consider and require reporting of the conversion of VOCs to CO₂ in the atmosphere. The purpose of this rule is to collect direct GHG emissions data from downstream sources including industrial wastewater treatment. Therefore we are not collecting data from downstream sources on indirect emissions such as VOCs that can convert to CO₂ once in the atmosphere. Please see "Technical Support Document for Industrial Wastewater Treatment" for more detailed information on this issue. While EPA is not requiring the reporting of CO₂ resulting from VOC emissions at this time, we understand that these emissions may be important and we may revisit this reporting requirement in the future.

Comment: EPA received many comments recommending that wastewater treatment be considered a *de minimis* source. Some argued that wastewater treatment contributes an extremely small percentage of emissions compared to certain sectors' process emissions. Others contended that the burden of determining the small amount of wastewater treatment emissions was not warranted.

Response: EPA disagrees that reporting of wastewater treatment emissions should be excluded from the rule. Despite the comparatively small amount of GHG emissions from wastewater treatment nationally,

emissions at individual facilities could be significant. We note that the source categories required to report are industries that both have the potential to exceed the reporting threshold, and have high levels of BOD or COD in their wastewater and frequently employ anaerobic treatment operations. See the Wastewater Treatment Technical Support Document (EPA-HQ-OAR-2008-0508-035). These two conditions result in the opportunity for increased GHG emissions. EPA has minimized the overall reporting burden by focusing the rule requirements on those treatment systems with the highest likelihood of generating GHG emissions exceeding the reporting threshold. In light of the potential significance of the emissions, lack of facility specific data, and revisions made to the reporting requirements in response to comments, we find that the burden on facilities is justified.

Given this reporting rule is aimed at collecting data to inform a range of future policies and programs it is important to understand the entirety of a facility's emissions. Therefore, requiring facilities in the included industry sectors to report wastewater treatment emissions, even though they may result in only a small portion of a facility's overall emissions, will allow each reporting facility to estimate their total emissions more accurately.

Comment: Many commenters requested additional flexibility in the rule requirements. Some requested the ability to use BOD instead of COD to calculate the organic content of the wastewater they treat in anaerobic processes. Others requested changes in sampling frequency for both biogas and wastewater.

Response: To reduce the reporting burden, EPA has revised the rule to allow for the use of either COD in conjunction with Equation II-1 of the rule or BOD₅ in conjunction with Equation II-2 of the rule for the calculation of CH₄ generation. EPA does not expect that this will effect the accuracy of the estimate of the annual mass of CH₄ generated at the facility.

EPA also revised the language regarding sampling of wastewater to require facilities to 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). Facilities are required to collect a minimum of four sample aliquots per 24-hour period and to composite the aliquots for analysis. This requirement provides for greater certainty that the collected

sample represents the wastewater influent to the anaerobic wastewater treatment process, without imposing unnecessary burden on reporters.

In response to comments, EPA considered revising the proposed language of 40 CFR 98.354 to clarify how facilities might meet the stated requirement for the collection of grab samples or time-weighted composite samples. EPA considered allowing facilities to collect grab samples if the wastewater influent to the anaerobic wastewater treatment process represents the discharge from a well-mixed wastewater storage unit (tank or pond), such that the COD or BOD₅ concentration of the waste stream does not vary in a 24-hour period. Similarly, EPA considered allowing facilities to collect time-weighted composite samples if the flow rate of the wastewater influent to the anaerobic wastewater treatment process does not vary more than ±50 percent of the mean flow rate for a 24-hour sampling period. However, establishing that these conditions are met would require the facility to collect more samples than the proposed requirement to collect flow-weighted composite samples. Thus we did not include these sampling approaches in the final rule.

The final rule establishes differing requirements for the frequency of monitoring biogas flow and biogas CH₄ concentration. EPA expects that facilities that recover biogas will have existing gas flow meters, and is therefore requiring continuous monitoring of biogas flow from these facilities. EPA has revised the rule to allow either continuous or weekly monitoring of biogas CH₄ concentration. If a facility has equipment that continuously monitors CH₄ concentration, the facility must use this equipment to determine the CH₄ concentration in the recovered biogas. If a facility does not currently monitor biogas CH₄ concentration, they must use either installed or portable equipment to monitor the CH₄ concentration at least once a week. Once a week means once each calendar week, with at least three days between measurements. Weekly monitoring provides an adequate number of samples to evaluate the variability and uncertainty associated with CH₄ generation. Less frequent monitoring would result in greater uncertainty and would not significantly reduce the costs compared to weekly monitoring.

Some gas flow meters and gas composition meters automatically compensate for temperature, pressure, and moisture content. EPA revised the equations in 40 CFR part 98, subpart II

so that facilities that use automatically compensated meters are not required to measure temperature, pressure and moisture content. Facilities that operate meters that are not automatically compensated must measure these parameters as specified in 40 CFR 98.354.

Some facilities, particularly food processing facilities, may not operate their wastewater treatment plants all year round. EPA clarified that wastewater monitoring requirements apply when the anaerobic wastewater treatment process is operating. Further, biogas methane concentration monitoring is only required in weeks when the cumulative biogas flow measured as specified in 40 CFR 98.354(g) is greater than zero.

Comment: Many commenters argued that it would be unduly burdensome and costly to require facilities to monitor influent to wastewater treatment systems. Some stated that their influent often consists of multiple phases, making measurement of wastewater organic content (BOD₅ or COD) difficult. Others contended that since effluent concentrations and flow are already measured for the purposes of National Pollutant Discharge Elimination System (NPDES) compliance, EPA should allow facilities to use engineering calculations and effluent measurements to calculate GHG emissions.

Response: The rule requires that flow and BOD₅ or COD be monitored at the location of influent to the anaerobic treatment process. EPA disagrees that facilities should be allowed to use the flow and organic loading of treated effluent to estimate CH₄ generation. CH₄ generation is a function of the organic load into the treatment system. If facilities used measured treated effluent organic load, they would need to back-calculate the influent (untreated) load. This approach would require EPA to describe all possible treatment scenarios, which would make the rule cumbersome and overly complex. Facilities would be required to use complex and burdensome methodologies to back-calculate the influent load.

Further, influent monitoring gives the most accurate determination of GHG emissions because it captures the inherent variability of the wastewater. In contrast, treated effluent characteristics typically have lower variability because high and/or variable influent concentrations have been reduced by treatment.

EPA also disagrees that monitoring the influent to the anaerobic process would be difficult because it consists of

multiple phases. EPA has revised 49 CFR 98.354(b) of the rule to clarify that flow and BOD₅ or COD concentration must be monitored 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). Such preliminary and primary treatment sufficiently removes the non-aqueous phases (oil, foam, suspended solids) that the wastewater stream that can be analyzed for BOD₅ and COD without undue burden.

EPA disagrees that the cost of monitoring would be an undue burden on facilities. The final rule continues to require facilities to collect and analyze samples of anaerobic treatment process influent no less than once per week. Weekly monitoring provides an adequate number of samples to evaluate the variability and uncertainty associated with CH₄ generation. Less frequent monitoring would result in greater uncertainty and would not significantly reduce the costs compared to weekly monitoring.

EPA has determined that the sampling methods contained in the rule are not unduly burdensome and still result in an accurate estimate of GHG emissions from industrial wastewater treatment processes for the purpose of this rulemaking.

F. Industrial Waste Landfills (40 CFR Part 98, Subpart TT)

1. Summary of the Final Rule

Source Category Definition. This source category consists of industrial waste landfills whose total landfill design capacity is greater than or equal to 300,000 metric tons and that accepted waste on or after January 1, 1980.

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 landfills, or landfills that only receive inert waste materials, such as coal combustion residue (e.g., fly ash), cement kiln dust, rocks and/or soil, glass, non-chemically bound sand (e.g., green foundry sand), clay, gypsum, pottery cull, bricks, mortar, cement, furnace slag, refractory material, or plastics.

Facilities that meet the applicability criteria in the General Provisions (40 CFR 98.2(a)) summarized in Section II.B of this preamble must report GHG emissions.

GHGs to Report. For industrial waste landfills, facilities must report:

- Annual CH₄ generation and CH₄ emissions from the industrial waste landfill.

- Annual CH₄ recovered (for landfills with gas collection and destruction systems).

GHG Emissions Calculation and Monitoring. All facilities must ascertain annual modeled CH₄ generation based on:

- Measured or estimated values of historic annual waste disposal quantities; and
- Appropriate values for model inputs (*i.e.*, degradable organic carbon (DOC) fraction in the waste, CH₄ generation rate constant). Default parameter values are specified for certain industries and for industrial waste generically.

Facilities that do not collect and destroy landfill gas must adjust the annual modeled CH₄ generation to account soil oxidation (CH₄ that is converted to CO₂ as it passes through the landfill cover before being emitted) using a default soil oxidation factor. The resulting value must be reported and represents both CH₄ generation (corrected for oxidation) and CH₄ emissions.

Facilities that collect and destroy landfill gas must calculate the annual quantity of CH₄ recovered and destroyed based on continuous monitoring of landfill gas flow rate, and continuous or weekly monitoring of CH₄ concentration, temperature, pressure, and moisture of the collected gas prior to the destruction device.

Those facilities that collect and destroy landfill gas must then calculate CH₄ emissions in two ways and report *both* results. Emissions must be calculated by:

1. Subtracting the measured amount of CH₄ recovered from the modeled annual CH₄ generation (with adjustments for soil oxidation and destruction efficiency of the destruction device) using the equations provided; and

2. Applying a gas collection efficiency to the measured amount of CH₄ recovered to “back-calculate” CH₄ generation, then subtracting the measured amount of CH₄ recovered (with adjustments for soil oxidation and destruction efficiency of the destruction device) from the back-calculated CH₄ generation using the equations provided. A default collection efficiency of 75 percent is specified, but landfills should use a collection efficiency that takes into account collection system coverage, operation, and landfill cover materials.

Data Reporting. In addition to the information required to be reported by

the General Provisions (40 CFR 98.3(c)), reporters must submit additional data that are used to calculate GHG emissions. A list of the specific data to be reported for this source category is contained in 40 CFR part 98, subpart TT.

Recordkeeping. In addition to the records required by the General Provisions (40 CFR 98.3(g)), reporters must keep records of additional data used to calculate GHG emissions. A list of specific records that must be retained for this source category is included in 40 CFR part 98, subpart TT.

2. Summary of Major Changes Since Proposal

The major changes since proposal are identified in the following list. The rationale for these and any other significant changes can be found below or in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Subpart TT: Industrial Waste Landfills.”

- A number of provisions were added to focus on industrial waste landfills that have a potential to generate significant quantities of methane rather than all landfills. These provisions include an exemption for landfills that did not accept any waste after January 1, 1980, an exemption of landfills with a total landfill design capacity of less than 300,000 metric tons, and an exemption for landfills that only receive inert waste materials.

- In addition to direct mass measurements for determining waste quantities for current reporting years, we also allow volume measurements, mass balance procedures, or number of truck loads.

- Additional model defaults for industrial waste are included in the final rule and additional methods are provided to estimate DOC content of industrial solid waste streams.

- For landfills with landfill gas recovery, all of the changes that were incorporated in the final 40 CFR part 98, subpart HH rule (allowing weekly sampling and direct flame ionization methods) are also included in this final rule for industrial waste landfills (by cross-referencing the final requirements in 40 CFR part 98, subpart HH). For additional details regarding the changes in the landfill gas recovery monitoring requirements, *see* the final preamble for the 40 CFR part 98, subpart HH [Municipal Solid Waste Landfills] rule at 74 FR 56336.

3. Summary of Comments and Responses

This section contains a brief summary of major comments and responses. EPA

received many comments on this subpart covering numerous topics. EPA’s responses to these significant comments can be found in the comment response document for industrial waste landfills in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Subpart TT: Industrial Waste Landfills.”

Definition of Source Category

Comment: Many commenters stated that landfills containing inert industrial wastes should not be subject to this proposed rule because inert wastes do not generate methane via anaerobic processes. Inert wastes, according to various commenters, include: construction and demolition waste, coal combustion residue monofills, geothermal filter cake waste landfills, waste rock landfills at coal mines, plastics, soils from construction and other site activities, hazardous waste landfills, solid waste management units (SWMUs) and non-hazardous landfills located at refineries, agricultural waste landfills associated with sugar mills, pottery cull, gypsum, clays, green sand, resin sand, refractory, slag, carbon and graphite manufacturing byproducts.

Several commenters stated that the rule would be very burdensome for industrial waste landfills with inert waste streams and that EPA has not sufficiently justified its decision to make all industrial waste landfills, regardless of typical byproduct waste characteristics, meet the provisions proposed.

Rather than listing specific exclusions, several commenters stated that EPA should do as suggested by the proposed rule and limit the requirements of the rule to landfills located at food processing, pulp and paper and ethanol production facilities which are known for methane gas generation; several commenters also included petroleum refineries in this list. One commenter suggested that ethanol production facilities should not be required to report landfill emissions because emissions from landfills at these facilities are so small.

A number of other exemptions were suggested by different commenters, including:

- Exempt inactive landfills, from which emissions are small.
- Exempt facilities that are not required to monitor methane or install and operate any methane control facilities under State permitting in order to keep the requirements simple and not overly burdensome.
- Exempt on-site industrial waste landfills that have been closed under RCRA because they have little or no

potential for air emissions and would create an unnecessary compliance burden.

Response: We agree that there will be negligible methane emissions from landfills that contain only inert waste materials because they do not have organic materials that would emit methane after being placed in an industrial landfill. Therefore, we investigated alternative applicability requirements for industrial waste landfills to target the reporting requirements to landfills that are expected to produce significant amounts of methane. Based on an analysis of various options (see the “Technical Support Document for Industrial Waste Landfills” in Docket No. EPA-HQ-OAR-2008-0508), we decided to exclude from the industrial waste landfill reporting requirements landfills that are used exclusively to dispose of inert materials or “inorganic” wastes. Specific types of wastes that are expected to be inert in the landfill (e.g., bricks, glass, plastics, rocks, and fly ash) are listed. This list of inert waste types also includes wastes that contain 0.5 weight percent (dry basis) or less of volatile solids as a means for industrial waste landfill owners and operators to characterize a waste stream as “inorganic” if the waste stream is not already on the list of inert materials. We did not provide exemptions for specific industries nor limit coverage to specific industries (e.g., ethanol production, food processing, or pulp and paper facilities) because the waste material generated and managed in a landfill at any given facility can be widely different, even within a given industry sector. As such, we determined that the waste material exclusions provided a better mechanism to exclude inert materials without omitting waste materials that have high organic content. Additional rationale regarding waste materials that were not specifically excluded is provided in the following paragraph.

- Geothermal filter cake. We anticipate that geothermal filter cake would be included in the exemption for rocks and soil from excavation activities. If this filter cake includes other materials, the landfills managing this waste may still be exempted if the waste can be shown to contain 0.5 weight percent (dry basis) or less of volatile solids. We note that this exclusion applies to any waste material at any industrial waste landfill (i.e., any of the following bullets).

- Landfills at petroleum refineries. We did not exclude landfills at petroleum refineries because we anticipate that refinery waste materials

will contain significant amounts of DOC.

- Agricultural wastes at sugar mills. Again, we did not exclude these wastes because we anticipate that the waste may contain significant amounts of DOC (scraps of sugar canes).

- Resin sand. While we excluded green sand (i.e., “non-chemically” bound sand, we did not exclude resin sand because resin sand generally contains organic chemical binders that can degrade in landfills and generate methane emissions.

- Carbon and graphite wastes. These wastes are expected to contain significant amounts of carbon. It is unclear if the carbon material can be degraded. However, with the information currently available regarding this waste stream, we could not conclude that these wastes are inert. If the graphite does not contain volatile impurities, it may be possible to exempt these wastes by demonstrating that the waste material contains 0.5 weight percent (dry basis) or less of volatile solids.

We also limited the reporting requirements for industrial waste landfills to facilities whose total landfill design capacity is greater than or equal to 300,000 metric tons. Our analysis indicated that there are a large number of very small industrial waste landfills. Approximately two-thirds of the total number of potentially affected industrial waste landfills have a total landfill design capacity of less than 300,000 metric tons, and these landfills are projected to contribute only 7 percent of the total GHG emissions from industrial waste landfills. Landfills with a design capacity of less than 300,000 metric tons are expected to have emissions well below 25,000 metric tons CO₂e. Landfills of this size would not be required to report emissions if they were not co-located at an industrial facility that has other emission sources exceeding the reporting threshold. The incremental costs for requiring these small co-located industrial waste landfills to report their landfill emissions was approximately \$1.25 per additional metric tons CO₂e reported (1st year costs), compared to approximately \$0.05 per metric tons CO₂e reported (1st year costs) for facilities with landfills whose total landfill design capacity is greater than or equal to 300,000 metric tons.

We also agree that certain inactive landfills can be excluded from the GHG reporting requirements. As described in the preamble to the final rule for municipal solid waste (MSW) landfills (74 FR 56335), landfills that have been closed over 30 years represent a small

fraction of GHG emissions from landfills and are not relevant for purposes of policy analysis. Therefore, we also limit the reporting requirements for industrial waste landfills to facilities that received waste on or after January 1, 1980.

We disagree that only industrial waste landfills that are required to monitor for methane or that are required to capture and destroy methane emissions should be included in the rule. Methane has not traditionally been a pollutant for which monitoring or destruction requirements have been established. We do not know of any such requirements, and available information indicates that few, if any, industrial waste landfills have methane capture and destruction equipment. Although few industrial landfills capture and destroy methane, that does not mean that these landfills do not generate methane in significant quantities.

As proposed, the industrial waste landfill source category did not include hazardous waste landfills or dedicated construction and demolition landfills. The final rule also excludes these landfills, however, we have clarified that hazardous waste landfills refers to those subject to RCRA Subtitle C or TSCA requirements. These landfills are excluded due to the landfill design requirements, such as “dry tomb” methods, which are expected to minimize methane production.

We have not exempted Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) (Superfund) landfills. Generally, landfills become listed as CERCLA sites because the landfills were not designed for hazardous wastes but some hazardous materials were disposed of in the landfill and subsequently these materials contaminated the groundwater. Thus, these landfills were not designed and operated in a manner similar to RCRA Subtitle C or TSCA landfills. Furthermore, the remediation requirements for CERCLA landfills are determined on a site-specific basis, and these methods generally do not necessarily require significant changes to the landfill. For example, clean-up efforts focused on groundwater remediation may pump and treat the contaminated groundwater and recirculate the treated groundwater to the landfill. This technique can be used to clean-up the groundwater and leach any other remaining contaminants from the landfill, but this technique will enhance rather than limit methane generation from the landfill. Consequently, landfills that are subsequently listed by States as “hazardous” for the purposes of

CERCLA (Superfund) or similar State programs are not excluded from the industrial waste landfill source category.

In summary, the final industrial waste landfill rule does not apply to: (1) Industrial waste landfills that have not accepted waste on or after January 1, 1980; (2) industrial waste landfills that have a total design capacity of less than 300,000 metric tons; (3) RCRA Subtitle C or TSCA hazardous waste landfills; (4) dedicated construction and demolition landfills; and (5) industrial waste landfills that receive only one or more of the following types of waste materials: coal combustion residue (*e.g.*, fly ash); cement kiln dust; rocks and/or soil from excavation and construction and similar activities; glass; non-chemically bound sand (*e.g.*, green foundry sand); clay, gypsum, or pottery cull; bricks, mortar, or cement; furnace slag; materials used as refractory (*e.g.*, alumina, silicon, fire clay, fire brick); plastics; or other waste material that has a volatile solids concentration of 0.5 weight percent (on a dry basis) or less.

Method for Calculating GHG Emissions

Comment: Several commenters suggested that EPA not require direct measurement of the waste entering the landfill. One commenter noted that there are materials that are conveyed and sluiced to solid waste disposal areas that could not be monitored across truck scales. The commenters suggested a number of alternatives to direct mass measurements, which include:

- Allow the use of company records.
- Allow the use of any measurement method specified in an applicable permit or any reasonable estimation method that is adequately documented.
- Allow the use of typical waste disposal records and other testing on parameters such as density and chemical analysis.
- Allow periodic calibration of the trucks hauling landfill waste to determine the weight to volume ratio of various waste streams provides a practical measurement for industrial waste landfills.
- Allow estimation methods outlined in the proposal to calculate previous years' data be applied in future years (*i.e.*, require direct waste measurements for only one year).

Response: Unlike MSW landfills, many industrial waste landfills do not directly weigh waste loads as they enter the landfill. We reevaluated the cost of requiring direct mass measurements for industrial waste landfills. According to one of the commenters, the capital cost of installing scales could be as much as \$50,000 each, with operating and driver

time resulting in an estimated annualized cost of over \$23,000. We also considered the uncertainty associated with different measuring methods and their resulting uncertainty in the overall modeled methane generation. Given the significant additional costs for requiring direct mass measurements at industrial waste landfills and the limited improvement in the uncertainty of the reported methane emissions, we revised the rule so that direct mass measurements are not required for industrial waste landfills.

In 40 CFR 98.463 of the final rule, industrial waste landfills that are subject to the rule are given several options for determining the current waste quantities and historical values for waste quantities and DOC. The types of processes that generate the waste, the types of waste generated, and the means by which the wastes are transported or conveyed to the landfill are very diverse. As such, different methods of determining these waste quantities are needed. Consequently waste quantities determined for years for which emissions reports are required may be determined by any of the following methods: direct mass measurements; volume measurements and waste stream density determined from measurement data or process knowledge; 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; and the number of loads (*e.g.*, trucks) and the mass of waste per load based on the working capacity of the container or vehicle.

We determined these methods accommodate the approaches requested by the commenters except for the last bulleted item. We do not agree with the commenter's request to allow projections of waste quantities disposed of after the first reporting year based on processing rate correlations used to project historical waste quantities. This method would not account for processing changes that may reduce (or increase) the waste generation rate. Given the flexibility in determining waste disposal quantities in a given reporting year, we determined that the costs of determining these waste quantities as provided in the final rule are reasonable and that the provided methods would produce more accurate values for the purposes of reporting than the "future" projection of waste quantities based on a single year of measurement data.

We also provide a number of methods by which historical waste quantities must be determined subject to the

hierarchy of available data. Historical waste quantities must be determined using the methods specified for current waste quantities when that information is available. For years when waste quantity data are not available, historical waste quantities must be estimated using production or processing rates when these data are available. For years when neither waste quantity data nor production/processing rate data are available, historical waste quantities must be estimated based on the capacity of the landfill used and the number of years the landfill has accepted waste.

Comment: Several commenters requested that more information be provided in the rule to calculate GHG emissions from industrial waste landfills, including an expansion of the type of information in Table HH-1 of the rule, especially if reporting of GHG emissions from industrial waste landfills is not limited to the food processing, pulp and paper, and ethanol production facilities. One commenter suggested that, if there are no DOC or k parameters in Table HH-1 for a given waste category, such as boiler ashes, reporters should assume they are zero and that no CH₄ is generated from that waste. According to the commenter, this assumption would more accurately calculate CH₄ emissions from a landfill by excluding quantities of inert wastes rather than assuming all wastes generate CH₄.

Response: We have specifically included a default DOC value of zero for inert materials in Table TT-1. Inert material is described as any waste material (such as glass, cement, and fly ash) that is specifically listed in § 98.460(b)(3) paragraphs (i) through (xii). As discussed previously, industrial waste landfills that receive only inert materials are not required to report, but landfills that receive both degradable organic and inert waste streams may use the default DOC for the quantity of inert material disposed of in the industrial waste landfill. For all other (non-inert) waste materials, the final rule allows either the use of Table TT-1 to determine the default values for DOC or the use of measured, waste stream-specific DOC values following the methods provided in the final rule. In addition to default DOC and k values for selected industries, we have also included in Table TT-1 of 40 CFR part 98, subpart TT default DOC and k value for "other solid industrial waste (not otherwise specified)." As such, there should no longer be an "unlisted" waste stream.

Costs

Comment: One commenter stated that EPA presents its summary cost analysis data in the preamble with further details in the accompanying regulatory impact analysis (RIA) report. The commenter stated that EPA presented cost data for each of the subparts separately but fails to consider the overall burden per facility of complying with multiple subparts, including landfills, as is the case with most industrial facilities.

Response: EPA agrees that the costs facing facilities in some sectors include not only process costs but additional costs associated with other subparts in the rule. While these costs are presented individually in the costs tables, where these conditions apply the costs are summed across applicable subparts and compared to revenues in the economic and small entity impact analyses. In response to comments on this issue, we revised the RIA of the 2009 final rule to more clearly describe the approach taken. The same approach has been taken for this rule.

III. Other Source Categories Proposed in 2009

A. Overview

With this action EPA has made the final decision not to include Ethanol Production or Food Processing as distinct subparts in 40 CFR part 98. This decision does not change the applicability requirements under other subparts of this rule that may affect these industries. Further explanation of this decision is included in Section III.B and III.C of this preamble. EPA has also made the final decision to not include Suppliers of Coal in 40 CFR part 98 at this time. Further explanation of this decision is included in Section III.D of this preamble.

B. Ethanol Production

EPA has made the final decision not to include Ethanol Production (proposed as 40 CFR part 98, subpart J) as a distinct subpart in 40 CFR part 98. EPA has determined that it is not necessary to include 40 CFR part 98, subpart J in order to cover ethanol facilities in the final rule. Thus, although there is no distinct subpart applicable to ethanol production, these facilities will still be subject to the final rule (if emissions exceed the applicable threshold) and the overall coverage of the final rule regarding these facilities is the same as that of the proposed rule.

The proposal for this subpart (74 FR 16448, April 10, 2009) did not include any unique requirements for monitoring or reporting of process emissions from ethanol production facilities. Instead,

the proposed subpart simply referred to reporting that those facilities might be required to do under other subparts, namely, 40 CFR part 98, subpart C—Stationary Combustion, subpart HH—Landfills, and subpart II—Wastewater Treatment.

EPA received many comments on this subpart covering various topics. EPA's response to these comments can be found in the comment response document for ethanol production in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart J: Ethanol Production."

40 CFR part 98, subpart J was originally included as a distinct subpart to clearly indicate that these facilities must aggregate emissions from all source categories when determining whether emissions exceeded the applicable threshold. As structured, the proposed subpart specifically required that emissions from stationary combustion, on-site landfills, and on-site wastewater treatment were to be aggregated in determining the reporting threshold and reporting emissions from these facilities.

Upon closer examination of 40 CFR 98.2(a), it is clear that ethanol production facilities are already required to report if they meet the threshold of 25,000 tons CO₂e by aggregating emissions from all applicable source categories in the rule including stationary combustion, industrial wastewater treatment, industrial waste landfills, miscellaneous use of carbonates, and any others that may apply. In fact, any type of facility not specifically identified in a subpart must report their GHG emissions if that facility contains source categories itemized by the rule and their aggregate emissions meet the applicable threshold.

Note that in this final rule, ethanol production facilities are among those specifically identified in 40 CFR part 98, subpart II—Industrial Wastewater Treatment and are required to report if they meet the applicability provisions in 40 CFR 98.2(a)(2). Thus for clarity, the definition of ethanol production facility is included in 40 CFR 98.358.

Again, in sum, EPA has determined that it is not necessary to include 40 CFR part 98, subpart J in order to cover ethanol facilities in the final rule. Moreover, highlighting the ethanol production (and food processing) categories as being covered by the rule due to emissions covered by other source categories may give the false impression that there are not any other types of sources that may be covered by the rule due to their aggregate emissions

from stationary combustion, industrial waste landfills and/or industrial wastewater treatment.

C. Food Processing

EPA has made the final decision not to include Food Processing (proposed as 40 CFR part 98, subpart M) as a distinct subpart in 40 CFR part 98. EPA had determined that it is not necessary to include 40 CFR part 98, subpart M in order to cover food processing facilities in 40 CFR part 98. Thus, although there is no distinct subpart applicable to food processing, these facilities will still be subject to the final rule (if emissions exceed the applicable threshold) and the overall coverage of the final rule regarding these facilities is the same as that of the proposed rule.

The proposal for this subpart (74 FR 16448, April 10, 2009) did not include any unique requirements for monitoring or reporting of process emissions from food processing facilities. Instead, the proposed subpart simply referred to reporting that those facilities might be required to do under other subparts, namely, 40 CFR part 98, subpart C—Stationary Combustion, subpart HH—Landfills, and subpart II—Wastewater Treatment.

EPA received many comments on this subpart covering various topics. EPA's response to these comments can be found in the comment response document for food processing in "Mandatory Greenhouse Gas Reporting Rule: EPA's Response to Public Comments, Subpart M: Food Processing."

40 CFR part 98, subpart M was originally included as a distinct subpart to clearly indicate that these facilities must aggregate emissions from all source categories when determining whether emissions exceeded the applicable threshold. As structured, the proposed subpart specifically required that emissions from stationary combustion, on-site landfills, and on-site wastewater treatment were to be aggregated in determining the reporting threshold and reporting emissions from these facilities.

Upon closer examination of 40 CFR 98.2(a), it is clear that food processing facilities are already required to report if they meet the threshold of 25,000 tons CO₂e by aggregating emissions from all applicable source categories in the rule including stationary combustion, industrial wastewater treatment, industrial waste landfills, miscellaneous use of carbonates, and any others that may apply. In fact, any type of facilities not specifically identified in a subpart must report their GHG emissions if that facility contains source categories

itemized by the rule and their aggregate emissions meet the applicable threshold.

Note that in this final rule, food processing facilities are among those specifically identified in 40 CFR part 98, subpart II—Industrial Wastewater Treatment and are required to report if they meet the applicability provisions in 40 CFR 98.2(a)(2). Thus, for clarity, a definition of food processing facility is included in 40 CFR 98.358.

Again, in sum, EPA has determined that it is not necessary to include 40 CFR part 98, subpart M in order to cover food processing facilities in the final rule. Moreover, highlighting the food processing (and ethanol production) categories as being covered by the rule due to emissions covered by other source categories may give the false impression that there are not any other types of sources that may be covered by the rule due to their aggregate emissions from stationary combustion, industrial waste landfills and/or industrial wastewater treatment.

D. Suppliers of Coal

As proposed (74 FR 16448, April 10, 2009) 40 CFR part 98, subpart KK would have required that all coal mines, coal importers and exporters, and coal waste reclaimers report the amount of coal produced or supplied to the economy annually, as well as the CO₂ emissions that would result from complete oxidation or combustion of this quantity of coal. After reviewing the comments received on the proposal as well as other available information, EPA has made a final decision not to include Suppliers of Coal (proposed as 40 CFR part 98, subpart KK) in 40 CFR part 98 at this time.

EPA's rationale for not requiring reporting from coal suppliers at this time is that (i) the overlap in reporting from upstream coal suppliers and downstream emitters is almost 100 percent indicating that double-reporting does not provide more complete information to EPA, unlike with other upstream supplier subparts (e.g., 40 CFR part 98, subpart MM and NN), and (ii) the high accuracy of the downstream reporting provisions in 40 CFR part 98 provide more than adequate emissions data for anticipated near-term uses.

The overall purpose of 40 CFR part 98 is to collect information to inform the development of future climate policy and programs under the CAA. In the context of GHG emissions from coal consumption, EPA seeks information on the magnitude and location of facility-level emissions across the economy as well as overall emissions at the national level. These near-term needs can be met

with high accuracy and at principally the same coverage through existing reporting requirements for direct emitters under 40 CFR part 98, primarily through reporting under 40 CFR part 98, subparts C, D, and Q. For example, the existing 40 CFR part 98, subpart D, which accounts for approximately 94 percent of emissions from the use of coal, builds on rigorous monitoring requirements of 40 CFR part 75. Coal-fired electricity generating units subject to 40 CFR part 75 typically use continuous emissions monitoring equipment that measures actual carbon dioxide emissions hourly. Furthermore, 40 CFR part 98 requires rigorous Tier 3 and Tier 4 reporting at industrial facilities with large units combusting coal and other solid fuels. Reporting requirements under 40 CFR part 98, subpart C (general stationary combustion) and 40 CFR part 98, subpart D (electricity generation) will allow EPA to obtain data on more than 99 percent of total CO₂ emissions from coal combustion through existing reporting provisions of 40 CFR part 98. The proposed 40 CFR part 98, subpart KK procedures would have covered approximately 100 percent of coal supplied to the economy and resulting downstream CO₂ combustion emissions. The difference in combustion coverage of less than 1 percent is estimated to come from the smallest consumers of coal, such as home owners for use in heating.

Furthermore, EPA's near-term needs regarding the data can be met with higher accuracy through existing reporting requirements for direct emitters. Under the proposed 40 CFR part 98, subpart KK, approximately 50 percent of coal suppliers would have used engineering calculations to correlate HHV from daily coal samples with carbon content from either daily or monthly coal samples, assuming those are representative of the entire coal stream. For the remaining coal mines, the proposed 40 CFR part 98, subpart KK procedures would have relied on default CO₂ emissions values, which are less accurate than direct measurement and would not have supplied mine specific data. Furthermore, existing reporting procedures for direct emitters account for the combustion efficiency of the facility rather than assume 100 percent combustion or oxidation as was proposed in 40 CFR part 98, subpart KK.

While EPA believes that the proposal had a pragmatic approach to balancing accuracy and cost, it is clear that the upstream data under proposed 40 CFR part 98, subpart KK would not have been as accurate as the more rigorously monitored data reported by direct

emitters. In sum, including proposed 40 CFR part 98, subpart KK would have provided EPA with a near negligible amount of additional information on emissions, while not achieving the same level of accuracy as the existing reporting downstream.

Though cost and burden are not reasons for EPA's decision to exclude 40 CFR part 98, subpart KK, EPA notes that changing the 40 CFR part 98, subpart KK proposal to require more rigorous reporting on par with downstream requirements would have raised the costs and burden of proposed 40 CFR part 98, subpart KK significantly. In the proposed Regulatory Impacts Analysis Cost Appendix Section 29, EPA assumed that 52 percent of coal mines (706) mines would meet 40 CFR part 98, subpart KK requirements by sampling and testing for coal content monthly and that 48 percent (659 mines) would meet requirements by using default factors. To raise the reporting rigor, EPA would have had to require 100 percent of coal mines (1,365 mines) to sample and test coal content daily.

In addition, there is other information available to EPA such as the *Inventory of U.S. Greenhouse Gas Emissions and Sinks*,⁴ other data reported by coal-fired electricity generating units to EPA's Acid Rain Program, and the Energy Information Administration's (EIA) detailed coal production, consumption, imports and exports data.⁵ The national GHG inventory tracks CO₂ emissions from the combustion of coal across the entire economy for each year since 1990 and breaks down emissions according to economic sector. From this data set EPA determined that in 2007, electricity generation accounted for approximately 94 percent of all CO₂ emissions from coal combustion. The remaining emissions from coal consumption come primarily from the industrial sector. EIA collects and publishes annual data on coal production, consumption, imports and exports, thus providing an additional source of information to serve as a check on estimates of emissions from this sector and to inform potential policies and programs related to coal supply. As EPA has stated in this preamble and in the original 40 CFR part 98, subpart KK proposal, rigorous, direct CO₂ emissions measurements of coal combustion are preferred by EPA over the use of default CO₂ values for informing policies and programs that relate to stationary source emissions. However, policies and programs of another nature for which default

⁴ <http://www.epa.gov/climatechange/emissions/usinventoryreport.html>.

⁵ <http://www.eia.doe.gov/fuelcoal.html>.

emissions values are more appropriate and have been previously used by EPA, such as life cycle emissions considerations for National Environmental Policy Act (NEPA) analyses and Federal government climate change contribution analyses, can be adequately informed at this time by existing EIA data on coal production and default CO₂ emissions values.

EPA views potential double-reporting for emissions from other fossil fuels as appropriate where downstream reporting of all or the large majority of emissions is impractical and where the upstream and downstream reporting combine to provide the complete picture. Near complete downstream coverage, as is achieved with coal, is not possible for downstream users of petroleum, natural gas, or industrial gases. In many cases, the fossil fuels and industrial GHGs supplied by producers and importers are used and ultimately emitted by a large number of small sources, particularly in the commercial and residential sectors (e.g., HFCs emitted from home air conditioning units or CO₂ emissions from individual motor vehicles). EPA would have had to require reporting by hundreds or thousands of small facilities to cover all direct emissions. EPA determined it was more appropriate to require reporting by the suppliers of petroleum products, natural gas and natural gas liquids, and industrial gases and CO₂. As exhibited by Table 5–18 of the RIA of the October 2009 Final Rule, the downstream emitters requirements of the October 2009 Final Rule account for only 20 percent of petroleum supply, approximately 23 percent of natural gas supply and 28 percent of industrial gas supply. Comparatively, requiring reporting by suppliers of these fuels, accounts for a much larger percentage of emissions (100 percent for petroleum and industrial gas suppliers and approximately 68 percent for natural gas suppliers).

Some commenters suggested that 40 CFR part 98, subpart KK data on the carbon content of all coal supplied would have informed the downstream effects of emissions changes resulting from the changing carbon intensity of the fuel (which in turn assists in analyses such as Best Available Control Technology (BACT)). EPA notes that it did not propose that facilities affected by 40 CFR part 98, subpart KK would report information on their customers because coal from multiple suppliers can be blended together and sent to multiple customers. Therefore information on downstream effect would not have been available for use from the proposed 40 CFR part 98,

subpart KK. For other upstream categories, EPA also did not propose and does not require detailed information about specific customers. If EPA determines that such type of carbon content data are necessary for a specific analysis or determination, the Agency can request it at that time. The robust data being collected now on downstream CO₂ emissions are adequate for general policy analysis and will assist the Agency in targeting additional information requests in the future.

EPA's final decision is entirely consistent with the language of the various appropriations acts authorizing the expenditure of money for the reporting rule. The language in the FY2008 Appropriations Act instructed EPA to spend the money on a rule requiring reporting "in all sectors of the economy." The Joint Explanatory Statement provided that EPA should include upstream production "to the extent that the Administrator deems appropriate." The appropriations language grants EPA much discretion to determine the appropriate source categories to include in the reporting rule.

The phrase "all sectors of the economy" is not further elaborated in the FY2008 or later appropriations language. The term is ambiguous, and EPA may interpret it in any reasonable manner. See *Chevron, U.S.A. v. NRDC*, 467 U.S. 837 (1984). Notably, the phrase is not "all industrial sectors" but rather "all sectors of the economy." There is a difference between an industrial sector and a sector of the economy. The former typically refers to a specific type of industry, while the latter refers to categories of industries or businesses. For example, the North American Industrial Classification System (NAICS) is a two- through six-digit hierarchical classification system, offering five levels of detail, ranging from the broad economic sector to the narrower national industry. See <http://www.census.gov/eos/www/naics/faqs/faqs.html#q5> (last visited May 10, 2010) ("Each digit in the code is part of a series of progressively narrower categories, and the more digits in the code signify greater classification detail. The first two digits designate the economic sector, the third digit designates the subsector, the fourth digit designates the industry group, the fifth digit designates the NAICS industry, and the sixth digit designates the national industry.")⁶

⁶ Although we cite to the NAICS system as an example illustrating that sectors of the economy are considered to be broader than industrial groupings, we are not indicating that we think the

In the proposed rule, EPA used the term "sector" to refer both to different types of sectors of the economy and specific industrial sectors or source categories. Compare 74 FR 16467/1 (referring to source categories in the "agricultural and land use sectors") to 74 FR 16488/1 (referring to "adipic acid production sector"). Unfortunately, that usage may have caused some confusion, and lead some stakeholders to believe that the two types of sectors are interchangeable and equivalent. But as noted above, there are differences between sectors of the economy, industrial sectors and source categories in the reporting rule. EPA can cover a sector of the economy in the reporting rule without covering every type of source in that sector of the economy.

40 CFR part 98 already covers a broad and diverse selection of sources and emissions in the various sectors of the economy (e.g., fuel and industrial gas suppliers, motor vehicle manufacturers, underground coal mines, manufacturing facilities, universities and other facilities with stationary combustion). While EPA considers it reasonable to include more than one source category in any given sector of the economy, it is not required to include every possible source category.

In any event, the appropriations language at most denotes a Congressional intent to ensure that emissions from various economic sectors are covered by the rule. As noted above, 40 CFR part 98 already adequately covers emissions from coal combustion even without getting additional information from coal suppliers.

Finally, the Joint Explanatory Statement already contemplated that the Administrator may not "deem[] it appropriate" to include all possible upstream production and downstream sources. As explained above, the October 2009 Final Rule already thoroughly covers the emissions that result from coal combustion. That information, combined with other sources of information regarding the coal supply available to EPA, makes EPA's decision that it is not "appropriate" at this time to include coal suppliers in the rule entirely reasonable.

EPA will continue to assess the need for reporting from coal suppliers in the future in light of new information or identification of policy or program needs. If EPA were to decide in the future to add coal suppliers to 40 CFR

appropriations language requires EPA to cover sources from the 20 sectors covered by the NAICS.

part 98 it would initiate a new rulemaking process.

IV. Economic Impacts on the Rule

This section of the preamble examines the costs and economic impacts of the proposed rulemaking and the estimated economic impacts of the rule on affected entities, including estimated impacts on small entities. Complete detail of the economic impacts of the final rule can be found in the text of the EIA in the docket for this rulemaking (EPA-HQ-OAR-2008-0508).

A large number of comments on economic impacts of the rule were received covering numerous topics. Responses to significant comments received can be found in “Mandatory Greenhouse Gas Reporting Rule: EPA’s Response to Public Comments, Cost and Economic Impacts of the Rule.” Additional subpart specific comments and responses can be found in EPA’s Response to Public Comments subpart specific documents.

A. How were compliance costs estimated?

1. Summary of Method Used To Estimate Compliance Costs

EPA used available industry and EPA data to characterize conditions at

affected sources. Incremental monitoring, recordkeeping, and reporting activities were then identified for each type of facility and the associated costs were estimated. The annual costs reported in 2006\$. EPA’s estimated costs of compliance are discussed below and in greater detail in Section 4 of the EIA (EPA-HQ-OAR-2008-0508):

Labor Costs. The vast majority of the reporting costs include the time of managers, technical, and administrative staff in both the private sector and the public sector. Staff hours are estimated for activities, including:

- *Monitoring (private):* staff hours to operate and maintain emissions monitoring systems.
- *Recordkeeping and Reporting (private):* staff hours to gather and process available data and reporting it to EPA through electronic systems.
- *Assuring and releasing data (public):* staff hours to quality assure, analyze, and release reports.

Staff activities and associated labor costs will potentially vary over time. Thus, cost estimates are developed for start-up and first-time reporting, and subsequent reporting. Wage rates to monetize staff time are obtained from the Bureau of Labor Statistics (BLS).

Equipment Costs. Equipment costs include both the initial purchase price and any facility modification that may be required. Based on expert judgment, the engineering costs analyses annualized capital equipment costs with appropriate lifetime and interest rate assumptions. One-time capital costs are amortized over a 10-year cost recovery period at a rate of 7 percent.

B. What are the costs of the rule?

1. Summary of Costs

The total annualized costs incurred under the reporting rule would be approximately \$7.0 million in the first year and \$5.5 million in subsequent years (\$2006). This includes a public sector burden estimate of \$0.3 million for program implementation and verification activities. Table 3 of this preamble shows the first year and subsequent year costs by subpart. In addition, it presents the relative share of the total cost represented by each subpart.

TABLE 3—NATIONAL ANNUALIZED MANDATORY REPORTING COSTS ESTIMATES (2008\$): SUBPARTS T, KK, II, AND TT

Subpart	2007 NAICS	First year		Subsequent years	
		Millions 2006\$	Share	Millions 2006\$	Share
Subpart T—Magnesium Production.	331419 and 331492	\$0.1	2%	\$0.1	2%
Subpart FF—Underground Coal Mines.	212112	4.0	57%	2.8	51%
Subpart II—Industrial Wastewater Treatment.	322110, 322121, 322122, 322130, 311611, 311411, 311421, 325193, and 324110.	1.5	21	1.5	26
Subpart TT—Industrial Waste Landfills.	322110, 322121, 322122, 322130, 311611, 311411, and 311421.	1.1	16%	0.8	15%
Private Sector, Total	6.7	96%	5.2	95%
Public Sector, Total	0.3	4%	0.3	5%
Total	7.0	100%	5.5	100%

C. What are the economic impacts of the rule?

1. Summary of Economic Impacts

EPA prepared an economic analysis to evaluate the impacts of this rule on affected industries. To estimate the economic impacts, EPA first conducted a screening assessment, comparing the estimated total annualized compliance costs by industry, where industry is defined in terms of North American

Industry Classification System (NAICS) code, with industry average revenues. Average cost-to-sales ratios for establishments in affected NAICS codes are typically less than 1 percent.

These low average cost-to-sales ratios indicate that the rule is unlikely to result in significant changes in firms’ production decisions or other behavioral changes, and thus unlikely to result in significant changes in prices or

quantities in affected markets. Thus, EPA followed its Guidelines for Preparing Economic Analyses (EPA, 2002, p. 124–125) and used the engineering cost estimates to measure the social cost of the rule, rather than modeling market responses and using the resulting measures of social cost. Table 4 of this preamble summarizes cost-to-sales ratios for affected industries.

TABLE 4—ESTIMATED COST-TO-SALES RATIOS FOR AFFECTED ENTITIES
[First year, 2006\$]

2007 NAICS	NAICS description	Subpart	Average cost per entity (\$/entity)	All enterprises (%)
331419	Primary Smelting and Refining of Nonferrous Metal (except Copper and Aluminum).	T	\$10,520	0.1
331492	Secondary Smelting, Refining, and Alloying of Nonferrous Metal (except Copper and Aluminum).	T	10,520	0.1
212112	Bituminous Coal Underground Mining	FF	34,717	0.2
322110	Pulp Mills	TT	5,583	< 0.1
322121	Paper (except Newsprint) Mills	TT	5,583	< 0.1
322122	Newsprint Mills	TT	5,583	< 0.1
322130	Paperboard Mills	TT	5,583	< 0.1
311611	Animal (except Poultry) Slaughtering	TT	5,583	< 0.1
311411	Frozen Fruit, Juice, and Vegetable Manufacturing	TT	5,583	< 0.1
311421	Fruit and Vegetable Canning	TT	5,583	< 0.1
322110	Pulp Mills	II	4,235	< 0.1
322121	Paper (except Newsprint) Mills	II	4,235	< 0.1
322122	Newsprint Mills	II	4,235	< 0.1
322130	Paperboard Mills	II	4,235	< 0.1
311611	Animal (except Poultry) Slaughtering	II	3,963	< 0.1
311411	Frozen Fruit, Juice, and Vegetable Manufacturing	II	3,963	< 0.1
311421	Fruit and Vegetable Canning	II	3,963	< 0.1
325193	Ethyl Alcohol Manufacturing	II	5,140	< 0.1
324110	Petroleum Refineries	II	3,963	< 0.1

D. What are the impacts of the rule on small businesses?

1. Summary of Impacts on Small Businesses

As required by the RFA and SBREFA, EPA assessed the potential impacts of the rule on small entities (small businesses, governments, and non-profit organizations). (See Section V.C of this preamble for definitions of small entities).

EPA conducted a screening assessment comparing compliance costs for affected industry sectors to industry-

specific receipts data for establishments owned by small businesses. This ratio constitutes a “sales” test that computes the annualized compliance costs of this rule as a percentage of sales and determines whether the ratio exceeds some level (e.g., 1 percent or 3 percent).

The cost-to-sales ratios were constructed at the establishment level (average reporting program costs per establishment/average establishment receipts) for several business size ranges. This allowed EPA to account for receipt differences between

establishments owned by large and small businesses and differences in small business definitions across affected industries. The results of the screening assessment are shown in Table 5 of this preamble.

As shown, the cost-to-sales ratios are typically less than 1 percent for establishments owned by small businesses that EPA considers most likely to be covered by the reporting program (e.g., establishments owned by businesses with 100 or more employees).

TABLE 5—ESTIMATED COST-TO-SALES RATIOS BY INDUSTRY AND ENTERPRISE SIZE (FIRST YEAR, 2006\$) ^a

2007 NAICS	NAICS description	Subpart	SBA size standard (effective August 22, 2008)	Average cost per entity (\$/entity)	All enterprises	Owned by enterprises with:					
						1 to 20 employees ^b	20 to 99 employees	100 to 499 employees	500 to 749 employees	750 to 999 employees	1,000 to 1,499 employees
331419	Primary Smelting and Refining of Nonferrous Metal (except Copper and Aluminum).	T	750 employees.	\$10,520	0.1%	0.9%	0.2%	0.1%	D	D	D
331492	Secondary Smelting, Refining, and Alloying of Nonferrous Metal (except Copper and Aluminum).	T	750 employees.	\$10,520	0.1%	0.7%	0.1%	0.2%	D	D	D
212112	Bituminous Coal Underground Mining.	FF	500 employees.	\$34,717	0.2%	3.0%	3.4%	0.2%	D	D	D
322110	Pulp Mills	TT	750 employees.	\$5,583	<0.1%	0.4%	D	D	D	D	D
322121	Paper (except Newsprint) Mills.	TT	750 employees.	\$5,583	<0.1%	D	0.1%	D	D	D	D

TABLE 5—ESTIMATED COST-TO-SALES RATIOS BY INDUSTRY AND ENTERPRISE SIZE (FIRST YEAR, 2006\$) ^a—Continued

2007 NAICS	NAICS description	Subpart	SBA size standard (effective August 22, 2008)	Average cost per entity (\$/entity)	All enterprises	Owned by enterprises with:					
						1 to 20 employees ^b	20 to 99 employees	100 to 499 employees	500 to 749 employees	750 to 999 employees	1,000 to 1,499 employees
322122	Newsprint Mills	TT	750 employees.	\$5,583	<0.1%	D	D	D	NA	D	D
322130	Paperboard Mills.	TT	750 employees.	\$5,583	<0.1%	1.1%	0.1%	<0.1%	NA	D	D
311611	Animal (except Poultry) Slaughtering.	TT	500 employees.	\$5,583	<0.1%	0.5%	0.1%	<0.1%	D	D	<0.1%
311411	Frozen Fruit, Juice, and Vegetable Manufacturing.	TT	500 employees.	\$5,583	<0.1%	0.3%	0.1%	<0.1%	<0.1%	D	<0.1%
311421	Fruit and Vegetable Canning.	TT	500 employees.	\$5,583	<0.1%	0.4%	0.1%	<0.1%	<0.1%	<0.1%	<0.1%
322110	Pulp Mills	II	750 employees.	\$4,235	<0.1%	0.3%	D	D	D	D	D
322121	Paper (except Newsprint) Mills.	II	750 employees.	\$4,235	<0.1%	D	<0.1%	D	D	D	D
322122	Newsprint Mills	II	750 employees.	\$4,235	<0.1%	D	D	D	NA	D	D
322130	Paperboard Mills.	II	750 employees.	\$4,235	<0.1%	0.8%	<0.1%	<0.1%	NA	D	D
311611	Animal (except Poultry) Slaughtering.	II	500 employees.	\$3,963	<0.1%	0.4%	<0.1%	<0.1%	D	D	<0.1%
311411	Frozen Fruit, Juice, and Vegetable Manufacturing.	II	500 employees.	\$3,963	<0.1%	0.2%	<0.1%	<0.1%	<0.1%	D	<0.1%
311421	Fruit and Vegetable Canning.	II	500 employees.	\$3,963	<0.1%	0.3%	<0.1%	<0.1%	<0.1%	<0.1%	<0.1%
325193	Ethyl Alcohol Manufacturing.	II	1,000 employees.	\$5,140	<0.1%	D	D	D	D	NA	D
324110	Petroleum Refineries.	II	1,500 employees ^c .	\$3,963	<0.1%	0.1%	<0.1%	<0.1%	<0.1%	D	D
331419	Primary Smelting and Refining of Non-ferrous Metal (except Copper and Aluminum).	T	750 employees.	\$10,520	0.1%	0.9%	0.2%	0.1%	D	D	D

Note: D denotes that receipt data was not disclosed. NA denotes that the enterprise category is not applicable (*i.e.*, no enterprises were reported within this category). Receipt data in Table 5–7 has been adjusted to 2006\$ using the latest GDP implicit price deflator reported by the U.S. Bureau of Economic Analysis (103.257/92.118 = 1.121) <http://www.bea.gov/national/nipaweb/Index.asp> (accessed December 21, 2009).

^a The Census Bureau defines an enterprise as a business organization consisting of one or more domestic establishments that were specified under common ownership or control. The enterprise and the establishment are the same for single-establishment firms. Each multi-establishment company forms one enterprise—the enterprise employment and annual payroll are summed from the associated establishments. Enterprise size designations are determined by the summed employment of all associated establishments.

Since the SBA's business size definitions (<http://www.sba.gov/size>) apply to an establishment's ultimate parent company, we assume in this analysis that the enterprise definition above is consistent with the concept of ultimate parent company that is typically used for Small Business Regulatory Enforcement Fairness Act (SBREFA) screening analyses.

^b Excludes *Statistics of U.S. Businesses* (SUSB) employment category for zero employees. These entities only operated for a fraction of the year.

^c NAICS code 324110—in addition, the petroleum refiner must not have more than 125,000 barrels per calendar day total Operable Atmospheric Crude Oil Distillation capacity. Capacity includes owned or leased facilities as well as facilities under a processing agreement or an arrangement such as an exchange agreement or a throughput. The total product to be delivered under the contract must be at least 90 percent refined by the successful bidder from either crude oil or bona fide feedstocks.

E. What are the benefits of the rule for society?

EPA examined the potential benefits of 40 CFR part 98. EPA's previous analysis of 40 CFR part 98 discussed the benefits of a reporting system with respect to policy making relevance, transparency issues, and market efficiency. Instead of a quantitative analysis of the benefits, EPA conducted a systematic literature review of existing studies including government, consulting, and scholarly reports.

A mandatory reporting system will benefit the public by increased

transparency of facility emissions data. Transparent, public data on emissions allows for accountability of polluters to the public stakeholders who bear the cost of the pollution. Citizens, community groups, and labor unions have made use of data from Pollutant Release and Transfer Registers to negotiate directly with polluters to lower emissions, circumventing greater government regulation. Publicly available emissions data also will allow individuals to alter their consumption habits based on the GHG emissions of producers.

The greatest benefit of mandatory reporting of industry GHG emissions to government will be realized in developing future GHG policies. For example, in the EU's Emissions Trading System, a lack of accurate monitoring at the facility level before establishing CO₂ allowance permits resulted in allocation of permits for emissions levels an average of 15 percent above actual levels in every country except the United Kingdom.

Benefits to industry of GHG emissions monitoring include the value of having independent, verifiable data to present

to the public to demonstrate appropriate environmental stewardship, and a better understanding of their emission levels and sources to identify opportunities to reduce emissions. Such monitoring allows for inclusion of standardized GHG data into environmental management systems, providing the necessary information to achieve and disseminate their environmental achievements.

Standardization will also be a benefit to industry, once facilities invest in the institutional knowledge and systems to report emissions, the cost of monitoring should fall and the accuracy of the accounting should improve. A standardized reporting program will also allow for facilities to benchmark themselves against similar facilities to understand better their relative standing within their industry.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review

Under Executive Order (EO) 12866 (58 FR 51735, October 4, 1993) this action is a "significant action" because it raises novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the EO. Accordingly, EPA submitted this action to the Office of Management and Budget (OMB) for review under EO 12866 and any changes made in response to OMB recommendations have been documented in the docket for this action. In addition, EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is contained in the EIA, "Economic Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions: Subparts: T, FF, II, and TT". A copy of the analysis is available in the docket for this action (Docket Item EPA-HQ-OAR-2008-0508-2313) and the analysis is briefly summarized here. EPA's cost analysis, presented in Section 4 of the EIA, estimates the total annualized cost of the rule will be approximately \$7.0 million (in 2006\$) during the first year of the program and \$5.5 million in subsequent years (including \$0.3 million of programmatic costs to the Agency).

B. Paperwork Reduction Act

The information collection requirements in this rule have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.* The information collection

requirements are not enforceable until OMB approves them.

EPA plans to collect complete and accurate economy-wide data on facility-level GHG emissions. Accurate and timely information on GHG emissions is essential for informing future climate change policy decisions. Through data collected under this rule, EPA will gain a better understanding of the relative emissions of specific industries, and the distribution of emissions from individual facilities within those industries. The facility-specific data will also improve our understanding of the factors that influence GHG emission rates and actions that facilities are already taking to reduce emissions. Additionally, EPA will be able to track the trend of emissions from industries and facilities within industries over time, particularly in response to policies and potential regulations. The data collected by this rule will improve EPA's ability to formulate climate change policy options and to assess which industries would be affected, and how these industries would be affected by the options.

This information collection is mandatory and will be carried out under CAA section 114. Information identified and marked as CBI will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. However, emissions data collected under CAA section 114 cannot generally be claimed as CBI and will be made public.

For these final subparts, the projected cost and hour burden for non-Federal respondents is \$5.13 million and 66.0 million hours per year. The estimated average burden per response is 29.1 hours; the frequency of response is annual for all respondents that must comply with the rule's reporting requirements and the estimated average number of likely respondents per year is 683. The cost burden to respondents resulting from the collection of information includes the total capital cost annualized over the equipment's expected useful life (averaging \$0.5 million), a total operation and maintenance component (averaging \$1.6 million per year), and a labor cost component (averaging \$3.6 million per year).

Burden is defined at 5 CFR 1320.3(b). These cost numbers differ from those shown elsewhere in the EIA for these subparts because the information collection request (ICR) costs represent the average cost over the first three years of the rule, but costs are reported elsewhere in the EIA for the subparts for the first year of the rule and for subsequent years of the rule. In addition, the ICR focuses on respondent

burden, while the RIA for the final rule includes EPA Agency costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9. When this ICR is approved by OMB, the Agency will publish a technical amendment to 40 CFR part 9 in the **Federal Register** to display the OMB control number for the approved information collection requirements contained in this final rule.

C. Regulatory Flexibility Act (RFA)

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, a small entity is defined as a small business as defined by the Small Business Administration's regulations at 13 CFR 121.201; according to these size standards, criteria for determining if ultimate parent companies owning affected facilities are categorized as small vary by NAICS. Small entity criteria range from total number of employees at the firm fewer than 500 to number of employees fewer than 1,500; one affected NAICS, 324110, the petroleum refiner must have no more than 1,500 employees nor more than 125,000 barrels per calendar day total Operable Atmospheric Crude Oil Distillation capacity. Capacity includes owned or leased facilities as well as facilities under a processing agreement or an arrangement such as an exchange agreement or a throughput. The total product to be delivered under the contract must be at least 90 percent refined by the successful bidder from either crude oil or bona fide feedstocks. EIA tables 5-10 and 5-11 present small business criteria and enterprise size distribution data for affected NAICS.

EPA assessed the potential impacts of the final rule on small entities using a sales test, defined as the ratio of total annualized compliance costs to firm sales. Details are provided in Section 5.3 of the EIA. These sales tests examine the average establishment's total annualized mandatory reporting costs to the average establishment receipts for enterprises

within several employment categories. The average entity costs used to compute the sales test are the same across all of these enterprise size categories. As a result, the sales-test will overstate the cost-to-receipt ratio for establishments owned by small businesses, because the reporting costs are likely lower than average entity estimates provided by the engineering cost analysis.

The results of the screening analysis show that for most NAICS, the costs are estimated to be less than 1 percent of sales in all firm size categories. For one NAICS (322130 Paperboard Mills), the costs exceed 1 percent of sales for the 1–20 employee size category; for another NAICS (212112 Bituminous Coal Underground Mining), the costs exceed 1 percent of sales for the 1–20 and 20–100 employee size category. Previous “Regulatory Impact Analysis for the Mandatory Reporting of Greenhouse Gas Emissions” (EPA–HQ–OAR–2008–0508) illustrated that pulp and paper industry enterprises with less than 20 employees were unlikely to be covered by the rule. For mining facilities, EPA’s initial review of facility data suggests that mines owned by enterprises with less than 100 employees would also be unlikely to be covered by the rule.

After considering the economic impacts of today’s final rule on small entities, I therefore certify that this final rule will not have a significant economic impact on a substantial number of small entities.

Although this rule would not have a significant economic impact on a substantial number of small entities, the Agency nonetheless tried to reduce the impact of this rule on small entities, including seeking input from a wide range of private- and public-sector stakeholders. When developing the rule, the Agency took special steps to ensure that the burdens imposed on small entities were minimal. The Agency conducted several meetings with industry trade associations to discuss regulatory options and the corresponding burden on industry, such as recordkeeping and reporting. The Agency investigated alternative thresholds and analyzed the marginal costs associated with requiring smaller entities with lower emissions to report. The Agency also selected a hybrid method for reporting, which provides flexibility to entities and helps minimize reporting costs.

D. Unfunded Mandates Reform Act (UMRA)

Title II of the Unfunded Mandates Reform Act of 1995 (UMRA), Public

Law 104–4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on State, local, and Tribal governments and the private sector. Under Section 202 of the UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for final rules with “Federal mandates” that may result in expenditures to State, local, and Tribal governments, in the aggregate, or to the private sector, of \$100 million or more in any one year.

This final rule does not contain a Federal mandate that may result in expenditures of \$100 million or more for State, local, and Tribal governments, in the aggregate, or the private sector in any one year. Overall, EPA estimates that the total annualized costs of this final rule are approximately \$6.7 million in the first year, and \$5.3 million per year in subsequent years. Thus, this final rule is not subject to the requirements of UMRA sections 202 or 205.

This final rule is also not subject to the requirements of UMRA section 203 because it contains no regulatory requirements that might significantly or uniquely affect small governments. None of the facilities currently known to undertake these activities are owned by small governments.

E. Executive Order 13132: Federalism

These final subparts do not have federalism implications. They will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in EO 13132.

Entities affected by these final subparts are facilities that directly emit GHGs. These final subparts do not apply to governmental entities unless the government entity owns a facility that directly emits GHGs above threshold levels such as a landfill or large stationary combustion source, so relatively few government facilities would be affected. This regulation also does not limit the power of States or localities to collect GHG data and/or regulate GHG emissions. Thus, EO 13132 does not apply to this rule.

In the spirit of EO 13132, and consistent with EPA policy to promote communications between EPA and State and local governments, EPA specifically solicited comments on these subparts from State and local officials. For a discussion of outreach activities to State, local, or Tribal organizations, see Section IX of the preamble to the proposed rule (74 FR 16602).

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have Tribal implications, as specified in EO 13175 (65 FR 67249, November 9, 2000). This regulation applies directly to facilities that directly emit GHGs. Facilities expected to be affected by these final subparts are not expected to be owned by Tribal governments. Thus, EO 13175 does not apply to this action.

Although EO 13175 does not apply to these final subparts, EPA sought opportunities to provide information to Tribal governments and representatives during development of the proposed rule, which included these subparts being finalized today. See Section IX of the preamble to the proposed rule (74 FR 16602).

G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

EPA interprets EO 13045 (62 FR 19885, April 23, 1997) as applying only to those regulatory actions that concern health or safety risks, such that the analysis required under section 5–501 of the EO has the potential to influence the regulation. This action is not subject to EO 13045 because it does not establish an environmental standard intended to mitigate health or safety risks.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not a “significant energy action” as defined in EO 13211 (66 FR 28355 (May 22, 2001)), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. Further, we have concluded that this rule is not likely to have any adverse energy effects. This rule relates to monitoring, reporting and recordkeeping at facilities that directly emit GHGs and does not impact energy supply, distribution or use. Therefore, we conclude that this rule is not likely to have any adverse effects on energy supply, distribution, or use.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business

practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This rulemaking involves technical standards. For these final subparts, EPA has decided to use more than a dozen voluntary consensus standards from four different voluntary consensus standards bodies, including American Society for Testing and Materials (ASTM) and American Society for Mechanical Engineers (ASME).

These voluntary consensus standards will help facilities monitor, report, and keep records of GHG emissions. No new test methods were developed for this rule. Instead, from existing rules for source categories and voluntary GHG programs, EPA identified existing means of monitoring, reporting, and keeping records of GHG emissions. The existing methods (voluntary consensus standards) include a broad range of measurement techniques, including methods to measure gas or liquid flow and methods to analyze gases by gas chromatography. All except three of these methods have already been incorporated by reference in the October 2009 Final Rule. Thus, we are adding entries to 40 CFR 98.7 for new voluntary consensus standards and modifying the entries for other voluntary consensus standards to reflect their usage in these final subparts. Thus, the test methods are incorporated by reference into the final rule and are available as specified in 40 CFR 98.7.

By incorporating voluntary consensus standards into the subparts, EPA is both meeting the requirements of the NTTAA and presenting multiple options and flexibility for measuring GHG emissions.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

EO 12898 (59 FR 7629 (Feb. 16, 1994)) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States.

EPA has determined that these final subparts will not have

disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. These final subparts do not affect the level of protection provided to human health or the environment because they address information collection and reporting procedures.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the U.S. prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is not a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective September 10, 2010.

List of Subjects in 40 CFR Part 98

Environmental protection, Administrative practice and procedure, Greenhouse gases, Incorporation by reference, Suppliers, Reporting and recordkeeping requirements.

Dated: June 28, 2010.

Lisa P. Jackson,
Administrator.

■ For the reasons stated in the preamble, title 40, chapter I, of the Code of Federal Regulations is amended as follows:

PART 98—[AMENDED]

■ 1. The authority citation for part 98 continues to read as follows:

Authority: 42 U.S.C. 7401–7671q.

Subpart A—[Amended]

■ 2. Section 98.1 is amended by revising paragraph (b) to read as follows:

§ 98.1 Purpose and Scope.

(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.

■ 3. Section 98.2 is amended by revising paragraphs (a)(1), (a)(2), and (a)(4); and revising the third sentence of paragraph (i)(3) to read as follows:

§ 98.2 Who must report?

(a) * * *

(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 that emits 25,000 metric tons CO₂e 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.

* * * * *

(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.

* * * * *

(i) * * *

(3) * * * This paragraph (i)(3) does not apply to facilities with municipal solid waste landfills or industrial waste landfills, or to underground coal mines.

* * * * *

* * * * *

■ 4. Section 98.3 is amended by:
a. Revising paragraph (b) introductory text.

b. Removing and reserving paragraph (b)(1).

c. Revising paragraphs (b)(2), (c)(4)(i), (c)(4)(ii), (c)(4)(iii) introductory text, (c)(7), and (i)(1) to read as follows.

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

* * * * *

(b) *Schedule.* The annual GHG report must be submitted no later than March

31 of each calendar year for GHG emissions in the previous calendar year. As an example, for a facility that is subject to the rule in calendar year 2010, the first report must be submitted on March 31, 2011.

(1) [Reserved]

(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.

* * * * *

(c) * * *

(4) * * *

(i) Annual emissions (excluding biogenic CO₂) aggregated for all GHG from all applicable source categories listed in Tables A-3 and Table A-4 of this subpart and expressed in metric tons of CO₂e calculated using Equation A-1 of this subpart.

(ii) Annual emissions of biogenic CO₂ aggregated for all applicable source categories in listed in Tables A-3 and Table A-4 of this subpart.

(iii) Annual emissions from each applicable source category listed in Tables A-3 and Table A-4 of this subpart, expressed in metric tons of each GHG listed in paragraphs (c)(4)(iii)(A) through (c)(4)(iii)(E) of this section.

* * * * *

(7) A brief description of each “best available monitoring method” used according to paragraph (d) of this section, the parameter measured using the method, and the time period during which the “best available monitoring method” was used, if applicable.

* * * * *

(i) * * *

(1) Except as provided in paragraphs (i)(4) through (i)(6) of this section, flow meters and other devices (e.g., belt scales) that measure data used to calculate GHG emissions shall be calibrated using the procedures specified in this paragraph and each relevant subpart of this part. All measurement devices must be calibrated according to the manufacturer’s recommended procedures, an appropriate industry consensus standard, or a method specified in a relevant subpart of this part. All measurement devices shall be calibrated to an accuracy of 5 percent. For facilities and suppliers that are subject to this part on January 1, 2010, the initial calibration shall be conducted by April

1, 2010. For facilities and suppliers that become subject to this part after April 1, 2010, the initial calibration shall be conducted by the date that data collection is required to begin. Subsequent calibrations shall be performed at the frequency specified in each applicable subpart.

* * * * *

■ 5. Section 98.6 is amended by revising the definition of “anaerobic lagoon” and adding definitions for “Cement kiln dust,” “Degasification system,” “Destruction device,” “Furnace slag,” “Liberated,” “Municipal wastewater treatment plant,” “Ventilation well or shaft,” “Ventilation system,” and “Working capacity.”

§ 98.6 Definitions.

* * * * *

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.

* * * * *

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).

* * * * *

Degasification system means the entirety of the equipment that is used to drain gas from underground and collect it at a common point, such as a vacuum pumping station. This includes all degasification wells and gob gas vent holes at the underground coal mine. Degasification systems include surface pre-mining, horizontal pre-mining, and post-mining systems.

* * * * *

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.

* * * * *

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.

* * * * *

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.

* * * * *

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).

* * * * *

Ventilation well or shaft means a well 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. This includes all ventilation shafts and wells at the underground coal mine.

* * * * *

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.

* * * * *

- 6. Section 98.7 is amended by:
 - a. Revising paragraphs (d)(1) through (d)(5), and (d)(7) through (d)(10).
 - b. Revising paragraphs (e)(10), (e)(11), (e)(25), and (e)(42).
 - c. Adding paragraphs (e)(43) and (e)(44).
 - d. Revising paragraph (f)(2).
 - e. Adding paragraphs (k) through (m).

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

* * * * *

(d) * * *

(1) ASME MFC-3M-2004 Measurement of Fluid Flow in Pipes Using Orifice, Nozzle, and Venturi, incorporation by reference (IBR) approved for § 98.34(b), § 98.244(b),

§ 98.254(c), § 98.324(e), § 98.344(c), § 98.354(d), § 98.354(h), and § 98.364(e).

(2) ASME MFC-4M-1986 (Reaffirmed 1997) Measurement of Gas Flow by Turbine Meters, IBR approved for § 98.34(b), § 98.244(b), § 98.254(c), § 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 Flowmeters, IBR approved for § 98.34(b) and § 98.244(b), and § 98.354(d).

(4) ASME MFC-6M-1998 Measurement of Fluid Flow in Pipes Using Vortex Flowmeters, IBR approved for § 98.34(b), § 98.244(b), § 98.254(c), § 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 § 98.34(b), § 98.244(b), § 98.254(c), § 98.324(e), § 98.344(c), § 98.354(h), and § 98.364(e).

(7) ASME MFC-11M-2006 Measurement of Fluid Flow by Means of Coriolis Mass Flowmeters, IBR approved for § 98.244(b), § 98.254(c), § 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 § 98.244(b), § 98.254(c), § 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 Flowmeters, IBR approved for § 98.244(b) and § 98.354(d).

(10) ASME MFC-18M-2001 Measurement of Fluid Flow Using Variable Area Meters, IBR approved for

§ 98.244(b), § 98.254(c), § 98.324(e), § 98.344(c), § 98.354(h), and § 98.364(e).

* * * * *

(10) ASTM D1945-03 Standard Test Method for Analysis of Natural Gas by Gas Chromatography, IBR approved for § 98.34(b), § 98.74(c), § 98.164(b), § 98.324(d), § 98.244(b), § 98.254(d), § 98.344(b), and § 98.354(g).

(11) ASTM D1946-90 (Reapproved 2006) Standard Practice for Analysis of Reformed Gas by Gas Chromatography, IBR approved for § 98.34(b), § 98.74(c), § 98.164(b), § 98.254(d), § 98.324(d), § 98.344(b), § 98.354(g), and § 98.364(c).

(25) ASTM D4891-89 (Reapproved 2006), Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion, IBR approved for § 98.34(a), § 98.254(e), and § 98.324(d).

(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).

(2) GPA 2261-00 Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography, IBR approved for § 98.34(a), § 98.164(b), § 98.254(d), § 98.344(b), and § 98.354(g).

* * * * *

(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).

■ 7. Add Tables A-3, A-4, and A-5 to Subpart A to read as follows:

TABLE A-3 TO SUBPART A—SOURCE CATEGORY LIST FOR § 98.2(a)(1)

Source Categories^a Applicable in 2010 and Future Years

- Electricity generation units that report CO₂ 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 CH₄ in amounts equivalent to 25,000 metric tons CO₂e or more per year, as determined according to subpart HH of this part.

TABLE A-3 TO SUBPART A—SOURCE CATEGORY LIST FOR § 98.2(a)(1)—Continued

Manure management systems with combined CH₄ and N₂O emissions in amounts equivalent to 25,000 metric tons CO₂e or more per year, as determined according to subpart JJ of this part.

Additional Source Categories^a Applicable in 2011 and Future Years

Underground coal mines that are subject to quarterly or more frequent sampling by Mine Safety and Health Administration (MSHA) of ventilation systems (subpart FF).

^a Source categories are defined in each applicable subpart.

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

Source Categories^a Applicable in 2010 and Future Years

Ferrous alloy 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

Magnesium production (subpart T).

Industrial wastewater treatment (subpart II).

Industrial waste landfills (subpart TT).

^a Source categories are defined in each applicable subpart.

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 CO₂e or more.

(C) Exporters of an annual quantity of coal-to-liquid products that is equivalent to 25,000 metric tons CO₂e or more.

Petroleum product suppliers (subpart MM):

(A) All petroleum refineries that distill crude oil.

(B) Importers of an annual quantity of petroleum products that is equivalent to 25,000 metric tons CO₂e or more.

(C) Exporters of an annual quantity of petroleum products that is equivalent to 25,000 metric tons CO₂e or more.

Natural gas and natural gas liquids suppliers (subpart NN):

(A) All fractionators.

(B) All local natural gas distribution companies.

Industrial greenhouse gas suppliers (subpart OO):

(A) All producers of industrial greenhouse gases.

(B) Importers of industrial greenhouse gases with annual bulk imports of N₂O, fluorinated GHG, and CO₂ that in combination are equivalent to 25,000 metric tons CO₂e or more.

(C) Exporters of industrial greenhouse gases with annual bulk exports of N₂O, fluorinated GHG, and CO₂ that in combination are equivalent to 25,000 metric tons CO₂e or more.

Carbon dioxide suppliers (subpart PP):

(A) All producers of CO₂.

(B) Importers of CO₂ with annual bulk imports of N₂O, fluorinated GHG, and CO₂ that in combination are equivalent to 25,000 metric tons CO₂e or more.

(C) Exporters of CO₂ with annual bulk exports of N₂O, fluorinated GHG, and CO₂ that in combination are equivalent to 25,000 metric tons CO₂e or more.

Additional Supplier Categories Applicable^a in 2011 and Future Years

(Reserved)

^a Suppliers are defined in each applicable subpart.

■ 8. Add subpart T to read as follows:

Subpart T—Magnesium Production

Sec.

98.200 Definition of source category.

98.201 Reporting threshold.

98.202 GHGs to report.

98.203 Calculating GHG emissions.

98.204 Monitoring and QA/QC requirements.

98.205 Procedures for estimating missing data.

98.206 Data reporting requirements.

98.207 Records that must be retained.

98.208 Definitions.

Subpart T—Magnesium Production

§ 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 (SF₆).
- (2) HFC-134a.

(3) The fluorinated ketone, FK 5-1-12.

(4) Carbon dioxide (CO₂).

(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 CO₂, N₂O, and CH₄ 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:

$$E_x = (I_{B,x} - I_{E,x} + A_x - D_x) * 0.001 \quad (\text{Eq. T-1})$$

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:

$$E_{GHG} = \sum_{p=1}^n Q_p * 0.001 \quad (\text{Eq. T-2})$$

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:

$$Q_p = M_B - M_E \quad (\text{Eq. T-3})$$

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:

$$R_{\text{GHG}} = C_{\text{GHG}} / \text{Mg} * 0.001 \quad (\text{Eq. T-4})$$

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 CO₂, N₂, and/or dry air.

Cover gas means SF₆, 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.

■ 9. Add subpart FF to read as follows:

Subpart FF—Underground Coal Mines

Sec.

98.320 Definition of the source category.

98.321 Reporting threshold.

98.322 GHGs to report.

98.323 Calculating GHG emissions.

98.324 Monitoring and QA/QC requirements.

98.325 Procedures for estimating missing data.

98.326 Data reporting requirements.

98.327 Records that must be retained.

98.328 Definitions.

§ 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 well or shaft, including both those wells and shafts where gas is emitted and those where gas is sold, used onsite, or otherwise destroyed (including by flaring).

(2) Each degasification system well or shaft, including degasification systems deployed before, during, or after mining operations are conducted in a mine area. This includes both those wells and shafts where gas is emitted, and those where 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).

§ 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 CH₄ liberated from ventilation and degasification systems.

(b) You must report CH₄ destruction from systems where gas is sold, used onsite, or otherwise destroyed (including by flaring).

(c) You must report net CH₄ emissions from ventilation and degasification systems.

(d) You must report under this subpart the CO₂ emissions from coal mine gas CH₄ destruction occurring at the facility, where the gas is not a fuel input for energy generation or use (e.g., flaring).

(e) You must report under subpart C of this part (General Stationary Fuel

Combustion Sources) the CO₂, CH₄, and N₂O emissions from each stationary fuel combustion unit by following the requirements of subpart C. Report emissions from both the combustion of collected coal mine CH₄ and any other fuels.

(f) An underground coal mine that is subject to this part because emissions from source categories described in subparts C through PP of this part is not required to report emissions under subpart FF of this part unless the coal mine is subject to quarterly or more

frequent sampling of ventilation systems by MSHA.

§ 98.323 Calculating GHG emissions.

(a) For each ventilation shaft, vent hole, or centralized point into which CH₄ from multiple shafts and/or vent holes are collected, you must calculate the quarterly CH₄ liberated from the ventilation system using Equation FF-1 of this section. You must measure CH₄ content, flow rate, temperature, pressure, and moisture content of the gas using the procedures outlined in § 98.324.

$$CH_{4V} = n \left(V * MCF * \frac{C}{100\%} * 0.0423 * \frac{520^{\circ}R}{T} * \frac{P}{1 \text{ atm}} * 1,440 * \frac{0.454}{1,000} \right) \quad (\text{Eq. FF-1})$$

Where:

CH_{4V} = Quarterly CH₄ liberated from a ventilation monitoring point (metric tons CH₄).

V = Daily volumetric flow rate for the quarter (scfm) based on sampling or a flow rate meter. If a flow rate meter is used and the meter automatically corrects for temperature and pressure, 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})_n 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 methane emitted during the measurement period, volumetric basis (cubic feet water per cubic feet emitted gas).

C = Daily CH₄ concentration of ventilation gas for the quarter (% , wet basis).

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 CH₄ 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 = Pressure at which flow is measured (atm) for the quarter.

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) Daily values of V, MCF, C, T, and P 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 CH₄ liberated from ventilation systems (CH_{4VTotal}) as the sum of the CH₄ from all ventilation

monitoring points in the mine, as follows:

$$CH_{4VTotal} = \sum_{i=1}^m (CH_{4V})_i \quad (\text{Eq. FF-2})$$

Where:

CH_{4VTotal} = Total quarterly CH₄ liberated from ventilation systems (metric tons CH₄).

CH_{4V} = Quarterly CH₄ liberated from each ventilation monitoring point (metric tons CH₄).

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 CH₄ from multiple wells and/or vent holes are collected), you must calculate the weekly CH₄ liberated from the mine using CH₄ measured weekly or more frequently (including by CEMS) according to 98.234(c), CH₄ content, flow rate, temperature, pressure, and moisture content, and Equation FF-3 of this section.

$$CH_{4D} = \sum_{i=1}^n \left(V_i * MCF_i * \frac{C_i}{100\%} * 0.0423 * \frac{520^{\circ}R}{T} * \frac{P_i}{1 \text{ atm}} * 1,440 * \frac{0.454}{1,000} \right) \quad (\text{Eq. FF-3})$$

Where:

CH_{4D} = Weekly CH₄ liberated from at the monitoring point (metric tons CH₄).

V_i = Daily measured total 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 (scfm). If a flow rate meter is used and the meter automatically corrects for temperature and pressure, 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-(fH₂O)_i when V_i is measured on a wet basis and C_i is measured on a dry basis.

= 1/[1-(fH₂O)_i] when V_i is measured on a dry basis and C_i is measured on a wet basis.

(fH₂O) = Moisture content of the CH₄ emitted during the measurement period,

volumetric basis (cubic feet water per cubic feet emitted gas)

C_i = Daily CH₄ concentration of gas for the days in the week when the degasification system is in operation at that monitoring point (% , wet basis).

n = The number of days in the week that the system is operational at that measurement point.

0.0423 = Density of CH₄ at 520 °R (60 °F) and 1 atm (lb/scf).

520 °R = 520 degrees Rankine.

T_i = Daily temperature at which flow is measured ($^{\circ}$ R).
 P_i = Daily pressure at which flow is measured (atm).
 1,440 = Conversion factor (minutes/day).
 0.454/1,000 = Conversion factor (metric ton/lb).

(1) Daily values for V, MCF, C, T, and P must be based on measurements taken

at least once each calendar 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:

$$CH_{4DTotal} = \sum_{i=1}^m \sum_{j=1}^w (CH_{4D})_{i,j} \quad (\text{Eq. FF-4})$$

Where:

$CH_{4DTotal}$ = Quarterly CH_4 liberated from all degasification monitoring points (metric tons CH_4).

CH_{4D} = 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 degasification system wells or ventilation shafts is sold, used onsite, or otherwise destroyed

(including by flaring), 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.

$$CH_{4Destroyed} = CH_4 \times DE \quad (\text{Eq. FF-5})$$

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.

$$CH_{4DestroyedTotal} = \sum_{i=1}^d (CH_{4Destroyed})_d \quad (\text{Eq. FF-6})$$

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.

$$CH_4 \text{ emitted (net)} = CH_{4VTotal} + CH_{4DTotal} - CH_{4DestroyedTotal} \quad (\text{Eq. FF-7})$$

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.

$$CO_2 = CH_{4Destroyedonsite} * 44/16 \quad (\text{Eq. FF-8})$$

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 .

§ 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 CH₄ liberated from ventilation systems, determine whether CH₄ will be monitored from each ventilation well and shaft, 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 well or shaft, 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) and make quarterly measurements of flow rate, temperature, and pressure. The sampling and measurements must be made at the same locations as 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, airflow, temperature, and pressure measured, the hand-held methane and oxygen readings (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.

(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 CH₄ liberated at degasification systems, determine whether CH₄ 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 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).

(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 and methane composition 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 well site. Follow the sampling protocols for sampling of methane emissions from ventilation shafts, as described in § 98.324(b)(1).

(d) Monitoring must adhere to 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).

(e) All fuel flow meters, gas composition monitors, and heating value 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 (e)(1) through (7) of this section.

Alternatively, calibration procedures specified by the flow meter manufacturer may be used. Fuel flow meters, gas composition monitors, and heating value monitors shall be recalibrated either annually or at the minimum frequency specified by the manufacturer, whichever is more frequent. For fuel, flare, or sour gas flow meters, 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 CH₄ destruction, CH₄ 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 and pressure monitors must be 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, 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, and the technical basis for the estimated accuracy shall be recorded.

§ 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 CH₄ concentration, flow rate, temperature, and pressure 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.

§ 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 CH₄ liberated from each ventilation monitoring point (CH_{4v,m}), (metric tons CH₄).

(b) Weekly CH₄ liberated from each degasification system monitoring point (metric tons CH₄).

(c) Quarterly CH₄ destruction at each ventilation and degasification system destruction device or point of offsite transport (metric tons CH₄).

(d) Quarterly CH₄ emissions (net) from all ventilation and degasification systems (metric tons CH₄).

(e) Quarterly CO₂ emissions from on-site destruction of coal mine gas CH₄, where the gas is not a fuel input for energy generation or use (e.g., flaring) (metric tons CO₂).

(f) Quarterly volumetric flow rate for each ventilation monitoring point (scfm), date and location of each measurement, and method of measurement (quarterly sampling or continuous monitoring).

(g) Quarterly CH₄ concentration for each ventilation monitoring point, dates and locations of each measurement and method of measurement (sampling or continuous monitoring).

(h) Weekly volumetric flow used to calculate CH₄ liberated from degasification systems (scf) and method of measurement (sampling or continuous monitoring).

(i) Quarterly CEMS CH₄ concentration (%) used to calculate CH₄ liberated from degasification systems (average from daily data), or quarterly CH₄ concentration data based on results from weekly sampling data (C).

(j) Weekly volumetric flow used to calculate CH₄ destruction for each destruction device and each point of offsite transport (scf).

(k) Weekly CH₄ concentration (%) used to calculate CH₄ destruction (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) and pressure (atm) at which each sample is collected.

(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 and shaft, indication of whether the well or shaft is monitored individually, or as part of a centralized monitoring point. Note which method (sampling or continuous monitoring) was used.

(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.

§ 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.

■ 10. Add subpart II to read as follows.

Subpart II—Industrial Wastewater Treatment

Sec.

98.350 Definition of source category.

98.351 Reporting threshold.

98.352 GHGs to report.

98.353 Calculating GHG emissions.

98.354 Monitoring and QA/QC requirements.

98.355 Procedures for estimating missing data.

98.356 Data reporting requirements.

98.357 Records that must be retained.

98.358 Definitions.

Table II-1 to Subpart II—Emission Factors

Table II-2 to Subpart II—Collection

Efficiencies of Anaerobic Processes

Subpart II—Industrial Wastewater Treatment

§ 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 CO₂ and CH₄. 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.

§ 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 CH₄ generation, CH₄ emissions, and CH₄ recovered from treatment of industrial wastewater at each anaerobic lagoon and anaerobic reactor.

(b) You must report CH₄ emissions and CH₄ recovered from each anaerobic sludge digester.

(c) You must report CH₄ emissions and CH₄ 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 CO₂, CH₄, and N₂O from each stationary combustion unit associated with the landfill gas destruction device, if present, by following the requirements of subpart C of this part.

§ 98.353 Calculating GHG emissions.

(a) For each anaerobic reactor and anaerobic lagoon, estimate the annual mass of CH₄ 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 CH₄ generated using Equation II-1 of this section.

$$CH_4G_n = \sum_{w=1}^{52} [Flow_w * COD_w * B_o * MCF * 0.001] \quad (\text{Eq. II-1})$$

Where:

CH₄G_n = Annual mass CH₄ 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 (m³/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/m³), measured as specified in § 98.354(b) and (c).

B_o = Maximum CH₄ producing potential of wastewater (kg CH₄/kg COD), use the value 0.25.

MCF = CH₄ 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 the anaerobic reactors or anaerobic lagoon using methods for the determination of 5-day biochemical oxygen demand (BOD₅), then estimate annual mass of CH₄ generated using Equation II-2 of this section.

$$CH_4G_n = \sum_{w=1}^{52} [Flow_w * BOD_{5,w} * B_o * MCF * 0.001] \quad (\text{Eq. II-2})$$

Where:

CH₄G_n = Annual mass of CH₄ 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(m³/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/m³), measured as specified in § 98.354(b) and (c).

B_o = Maximum CH₄ producing potential of wastewater (kg CH₄/kg BOD₅), use the value 0.6.

MCF = CH₄ conversion factor, based on relevant values in Table II-1 of 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 CH₄ emissions using Equation II-3 of this section.

$$CH_4E_n = CH_4G_n \quad (\text{Eq. II-3})$$

Where:

CH₄E_n = Annual mass of CH₄ emissions from the wastewater treatment process n from which biogas is not recovered (metric tons).

CH₄G_n = Annual mass of CH₄ 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 digester, anaerobic reactor, or anaerobic lagoon from which some biogas is recovered, estimate the annual mass of CH₄

recovered according to the requirements in paragraphs (c)(1) and (c)(2) of this section. To estimate the annual mass of CH₄ recovered, you must continuously monitor gas flow rate as specified in § 98.354(f) and (h).

(1) If you continuously monitor CH₄ 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 CH₄ gas, as specified in § 98.354(g), you must use this monitoring system and calculate the quantity of CH₄ recovered for destruction using Equation II-4 of this section. A fully integrated system that directly reports CH₄ content requires only the summing of results of all monitoring periods for a given year.

$$R_n = \sum_{m=1}^M \left[(V)_m * (K_{MC})_m * \frac{(C_{CH_4})_m}{100\%} * 0.0423 * \frac{520^\circ R}{(T)_m} * \frac{(P)_m}{1 \text{ atm}} * \frac{0.454}{1,000} \right] \quad (\text{Eq. II-4})$$

Where:

- R_n = Annual quantity of CH₄ recovered from the nth anaerobic reactor, digester, or lagoon (metric tons CH₄/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 $(C_{CH_4})_m$ are measured on a dry basis or if both are measured on a wet basis.
- = $1 - (f_{H_2O})_m$ when $(V)_m$ is measured on a wet basis and $(C_{CH_4})_m$ is measured on a dry basis.
- = $1/[1 - (f_{H_2O})_m]$ when $(V)_m$ is measured on a dry basis and $(C_{CH_4})_m$ is measured on a wet basis.
- $(f_{H_2O})_m$ = Average moisture content of biogas during the measurement period, volumetric basis, (cubic feet water per cubic feet biogas).
- $(C_{CH_4})_m$ = Average CH₄ concentration of biogas during the measurement period, (volume %).
- 0.0423 = Density of CH₄ lb/cf at 520 °R or 60 °F and 1 atm.
- 520 °R = 520 degrees Rankine.
- T_m = Temperature at which flow is measured for the measurement period (°R). If the flow rate meter automatically corrects for temperature replace "520 °R/ T_m " with "1".
- P_m = Pressure at which flow is measured for the measurement period (atm). If the flow rate meter automatically corrects for pressure, replace " $P_m/1$ " with "1".
- 0.454/1,000 = Conversion factor (metric ton/lb).
- (2) If you do not continuously monitor CH₄ concentration according to

paragraph (c)(1) of this section, you must determine the CH₄ 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)(iii) of this section and calculate the quantity of CH₄ recovered for destruction using Equation II-4 of this section.

(i) Continuously monitor gas 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. 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)(iii) of this section.

(ii) Determine the CH₄ 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 once each calendar week, with at least three days between measurements. For a given calendar week, you are not required to determine CH₄ concentration if the cumulative volume of biogas for that calendar week, determined as specified in paragraph (c)(2)(i) of this section, is zero.

(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 biogas that is collected and routed to a destruction device in a location near or representative of the location of the gas flow meter once each calendar week, with at least three days between measurements.

(B) If the CH₄ concentration is determined on a dry basis and biogas flow is determined on a wet basis, or CH₄ 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 once each calendar week that the cumulative biogas flow measured as specified in § 98.354(h) is greater than zero, with at least three days between measurements.

(d) For each anaerobic digester, anaerobic reactor, or anaerobic lagoon from which some quantity of biogas is recovered, you must estimate both the annual mass of CH₄ that is generated, but not recovered, according to paragraph (d)(1) of this section and the annual mass of CH₄ emitted according to paragraph (d)(2) of this section.

(1) Estimate the annual mass of CH₄ that is generated, but not recovered, using Equation II-5 of this section.

$$CH_4L_n = R_n * \left(\frac{1}{CE} - 1 \right) \quad (\text{Eq. II-5})$$

Where:

- CH_4L_n = Leakage at the anaerobic process n (metric tons CH₄).
- n = Index for processes at the facility, used in Equation II-7.
- R_n = Annual quantity of CH₄ recovered from the nth anaerobic reactor, anaerobic lagoon, or anaerobic digester, as calculated in Equation II-4 of this section (metric tons CH₄).
- CE = CH₄ collection efficiency of anaerobic process n, as specified in Table II-2 of this subpart (decimal).

(2) For each anaerobic digester, anaerobic reactor, or anaerobic lagoon from which some quantity of biogas is recovered, estimate the annual mass of CH₄ emitted using Equation II-6 of this section.

$$CH_4E_n = CH_4L_n + R_n \left(1 - (DE_1 * f_{Dest_1}) \right) + R_n \left(1 - (DE_2 * f_{Dest_2}) \right) \quad (\text{Eq. II-6})$$

Where:

- CH_4E_n = Annual quantity of CH₄ emitted from the process n from which biogas is recovered (metric tons/yr).
- 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 CH₄).
- R_n = Annual quantity of CH₄ recovered from the nth anaerobic reactor or anaerobic digester, as calculated in Equation II-4 of this section (metric tons CH₄).
- DE_1 = Primary destruction device CH₄ destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99). If the gas is

transported off-site for destruction, use $DE = 1$.

f_{Dest_1} = Fraction of hours the primary destruction device was operating (device operating hours/hours in the year). If the gas is transported off-site for destruction, use $f_{Dest} = 1$.

DE_2 = Back-up destruction device CH₄ destruction efficiency (lesser of manufacturer's specified destruction efficiency and 0.99).

f_{Dest_2} = Fraction of hours the back-up destruction device was operating (device operating hours/hours in the year).

(e) Estimate the total mass of CH₄ 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.

$$CH_4E_T = \sum_{n=1}^j CH_4E_n \quad (\text{Eq. II-7})$$

Where:

- CH_4E_T = Annual mass CH₄ emitted from all anaerobic processes at the facility (metric tons).
- n = Index for processes at the facility.
- CH_4E_n = Annual mass of CH₄ emissions from process n (metric tons).

j = Total number of processes from which methane is emitted.

§ 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 BOD₅ 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 BOD₅ concentration once each calendar week that the anaerobic wastewater treatment process is operating, with at least three days between measurements. You must collect a sample that represents the average COD or BOD₅ 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 once each calendar week that the process is operating, with 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 BOD₅ concentration. The flow measurement location must correspond to the location used to collect samples analyzed for COD or BOD₅ 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, digester, or lagoon) from which biogas is recovered, you must continuously measure the gas flow rate as specified in paragraph (h) of this section and determine the cumulative volume of gas recovered as specified in Equation II-4 of this subpart. You must also determine the CH₄ 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 CH₄ 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. As specified in § 98.353(c) and paragraph (h) of this section, you must also determine temperature, pressure, and moisture content as necessary to accurately determine the gas flow rate and CH₄ 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 gas flow rate is measured on a wet basis and the CH₄ concentration is measured on a dry basis. You must also measure the moisture content of the recovered biogas if the gas flow rate is measured on a dry basis and the CH₄ concentration is measured on a wet basis.

(g) For each anaerobic process (such as an anaerobic reactor, digester, or lagoon) from which biogas is recovered, operate, maintain, and calibrate a gas composition monitor capable of measuring the concentration of CH₄ 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 CH₄ 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 CH₄ and determine the total gaseous organic concentration as carbon (or as CH₄; 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 CH₄ concentration as specified in Equation II–8 of this section.

$$C_{\text{CH}_4} = f_{\text{NMOC}} \times C_{\text{TGOC}} \quad (\text{Eq. II-8})$$

Where:

C_{CH_4} = Methane (CH₄) 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, 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 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.

(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 BOD₅ concentration, wastewater flow rate, gas flow rate, gas 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.

§ 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 BOD₅ 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 CH₄ content or gas 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.

§ 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. Explain 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 all anaerobic lagoons, 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 BOD₅ 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 CH₄ production potential (B₀) used as an input to Equation II-1 or II-2 of this subpart.

(4) Methane conversion factor (MCF) used as an input to Equation II-1 or II-2 of this subpart.

(5) Annual mass of CH₄ 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 CH₄ emissions, calculated using Equation II-3 of this subpart.

(d) For each anaerobic wastewater treatment process and anaerobic digester from which some biogas is recovered, you must report:

(1) Annual quantity of CH₄ recovered from the anaerobic process calculated using Equation II-4 of this subpart.

(2) Cumulative volumetric biogas flow for each week that biogas is collected for destruction.

(3) Weekly average CH₄ concentration for each week that biogas is collected for destruction.

(4) Weekly average 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 CH₄ 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 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) CH₄ 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 backup destruction device (if present).

(9) For each anaerobic process from which some biogas is recovered, you must report the annual CH₄ emissions, as calculated by Equation II-6 of this subpart.

(e) The total mass of CH₄ 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.

§ 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 CO₂, CH₄, 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—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

■ 11. Add and reserve subparts QQ, RR, and SS.

■ 12. Add subpart TT to read as follows:

Subpart TT—Industrial Waste Landfills

Sec.

98.460 Definition of the source category.

98.461 Reporting threshold.

98.462 GHGs to report.

98.463 Calculating GHG emissions.

98.464 Monitoring and QA/QC requirements.

98.465 Procedures for estimating missing data.

98.466 Data reporting requirements.

98.467 Records that must be retained.

98.468 Definitions.

Table TT-1 to Subpart TT—Default DOC and Decay Rate Values for Industrial Waste Landfills

Subpart TT—Industrial Waste Landfills

§ 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) Dedicated construction and demolition waste landfills. A dedicated construction and demolition waste landfill receives materials generated from the construction or destruction of structures such as buildings, roads, and bridges.

(2) Industrial waste landfills that only receive one or more of the following inert waste materials:

(i) Coal combustion residue (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).

(vi) Clay, gypsum, or pottery cull.

(vii) 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.

(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).

§ 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 CH₄ generation and CH₄ emissions from industrial waste landfills.

(b) You must report CH₄ 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 CO₂, CH₄, and N₂O 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 CH₄ 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 CH₄ generation rates for all waste streams disposed of in the landfill to calculate the total annual modeled CH₄ generation rate for the landfill.

(1) Calculate annual modeled CH₄ generation using Equation TT-1 of this section.

$$G_{CH_4} = \left[\sum_{x=S}^{T-1} \left\{ W_x \times DOC_x \times MCF \times DOC_F \times F_x \times \frac{16}{12} \times (e^{-k(T-x-1)} - e^{-k(T-x)}) \right\} \right] \quad (\text{Eq. TT-1})$$

Where:

G_{CH₄} = Modeled methane generation rate in reporting year T (metric tons CH₄).

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 year X from Table TT-1 of 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.

MCF = Methane correction factor (fraction); use the default value of 1.

F_x = Fraction by volume of CH₄ in landfill gas (fraction, dry basis). If you have a gas collection system, use the annual average

CH₄ concentration from measurement data for the given year; otherwise, use the default value of 0.5.

k = Decay rate constant from Table TT-1 of 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, 1980 or the year the landfills first accepted waste if after January 1, 1980, 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 monitoring 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 monitoring 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.

$$WDF = \left[\sum_{x=Y_1}^{Y_2} \left\{ \frac{W_x}{N \times P_x} \right\} \right] \quad (\text{Eq. TT-2})$$

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.

Y₁ = First year in which disposal and production/throughput data are both available.

Y₂ = 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.

$$W_x = WDF \times P_x \quad (\text{Eq. TT-3})$$

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 fixed average annual bulk waste disposal quantity for each year for which historic disposal quantity and Equation TT-4 of this section.

$$W_x = \frac{LFC}{(\text{YrData} - \text{YrOpen} + 1)} \quad (\text{Eq. TT-4})$$

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 "YrData" 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 year when waste disposal data is first available from company records or from Equation TT-3 of this section.

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.

(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.

$$DOC_{bulk} = \frac{\sum_{n=1}^N (DOC_{ave,n} \times W_{ave,n})}{\sum_{n=1}^N W_{ave,n}} \quad (\text{Eq. TT-5})$$

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.

$$MG = G_{CH_4} \times (1 - OX) \quad (\text{Eq. TT-6})$$

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. Use the default value of 0.1 (10 percent).

(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 CH₄ recovered according to the requirements at § 98.343(b).

(ii) Calculate CH₄ emissions using the Equation HH-6 of § 98.343(c)(3)(i), except use G_{CH₄} determined using Equation TT-1 of this section in Equation HH-6 of § 98.343(c)(3)(i).

(iii) Calculate CH₄ generation (MG) from the quantity of CH₄ recovered using Equation HH-7 of § 98.343(c)(3)(ii).

(iv) Calculate CH₄ emissions from the quantity of CH₄ recovered using Equation HH-8 of § 98.343(c)(3)(ii).

§ 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 for which you choose to determine volatile solids concentration for the purposes of paragraph § 98.460(c)(2)(xii) or choose

to determine a landfill-specific DOC_x for use in Equation TT-1 of this subpart, 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.

(1) Develop and follow a sampling plan to collect a representative sample of each waste stream 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) Calculate the volatile solids concentration (weight percent on a dry basis) using Equation TT-7 of this section.

$$C_{vs} = \frac{\% \text{ Volatile Solids}}{\% \text{ Total Solids}} \times 100\% \quad (\text{Eq. TT-7})$$

Where:

C_{vs} = Volatile solids concentration in the waste stream (weight percent, dry basis).

% Volatile Solids = Percent volatile solids determined using Standard Method

2540G "Total, Fixed, and Volatile Solids in Solid and Semisolid Samples" (incorporated by reference; see § 98.7).

% Total Solids = Percent total solids determined using Standard Method 2540G "Total, Fixed, and Volatile Solids

in Solid and Semisolid Samples" (incorporated by reference; see § 98.7).

(4) Calculate the waste stream-specific DOC_x value using Equation TT-8 of this section.

$$\text{DOC}_x = F_{\text{DOC}} \times \% \text{ Volatile Solids}_x \quad (\text{Eq. TT-8})$$

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.

(c) For landfills with gas collection systems, operate, maintain, and calibrate a gas composition monitor capable of measuring the concentration of CH₄ according to the requirements specified at § 98.344(b).

(d) 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).

(e) 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.

(f) 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.

§ 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 information:

(1) The number of waste streams (including "Other Industrial Solid Waste (not otherwise listed)") for which Equation TT-1 of this subpart is used to calculate modeled CH₄ generation.

(2) A description of each waste stream (including the types of materials in each waste stream).

(c) For each waste stream identified in paragraph (b) of this section, report the following information:

(1) The decay rate (k) value used in the calculations.

(2) The method(s) for estimating historical waste disposal quantities and the range of years for which each method applies.

(3) If 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 Equation TT-2 of this subpart applies.

(iii) The average waste disposal factor (WDF) calculated for the waste stream.

(4) If Equation TT-4 of this subpart is used, provide:

(i) The value of landfill capacity (LFC).

(ii) YrData.

(iii) YrOpen.

(d) For each year of landfilling starting with the "Start Year" (S) to the current reporting year, report the following information:

(1) The quantity of waste (W_x) disposed of in the landfill (metric tons, wet weight) for each waste stream identified in paragraph (b) of this section.

(2) The degradable organic carbon (DOC_x) value (mass fraction) and an indication as to whether this was the default value from Table TT-1 of this subpart or a value determined through sampling and calculation for each waste stream identified in paragraph (b) of this section.

(3) The fraction of CH₄ in the landfill gas (volume fraction, dry basis) and an indication as to whether this was the default value or a value determined through measurement data.

(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 rate for the reporting year (metric tons CH₄) 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, adjusted for oxidation, calculated using Equation TT-5 of this subpart), reported in metric tons CH₄.

(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, you must report according to § 98.346(i).

§ 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.

§ 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.

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.

TABLE TT-1 TO SUBPART TT—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	0.22	0.06	0.12	0.18
Pulp and Paper	0.20	0.02	0.03	0.04
Wood and Wood Product	0.43	0.02	0.03	0.04
Construction and Demolition	0.04	0.02	0.03	0.04
Inert Waste [<i>i.e.</i> , wastes listed in § 98.460(b)(3)]	0	0	0	0
Other Industrial Solid Waste (not otherwise listed)	0.20	0.02	0.04	0.06

^aThe 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 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.